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A Sensitivity Analysis of Central Station Flat-Plate Photovoltaic Systems and Implications for National Photovoltaics Program Planning

M.R. Crosetti
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August 30, 1985

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U.S. Department of Energy
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An analysis is made of the effects of regional differences in competing energy costs and solar insolation levels on the competitiveness of photovoltaic systems. The sensitivity of competing energy costs (coal, combustion turbine, and combined cycle oil-fired generators) to escalation rates for capital and fuel are explored. Alternative tracking configurations (fixed, one-axis, and two-axis tracking) are also introduced into the sensitivity analysis.

Goal values for photovoltaic system parameters were reviewed on the basis of the most recent research findings. Sensitivity tests were made to see how research progress in areas such as power-related balance of system cost affected the combinations of module cost and module efficiency that meet program goals for system energy costs.

ACKNOWLEDGMENTS

This study was performed under the purview of the Project Analysis and Integration Task as part of the Flat-Plate Solar Array Project at the Jet Propulsion Laboratory, Pasadena, California. The authors gratefully acknowledge Paul Henry and Lenny Reiter for their help in initiating this work, and Pat McGuire and Chet Borden for valuable discussions concerning some of the technical issues contained in this report. The authors appreciate the helpful editorial support provided by Laura Boghosian, and the prompt preparation of the document by Dottie Johnson.

GLOSSARY

ABBREVIATIONS AND ACRONYMS

AC	alternating current
AFDC	allowance for interest cost on funds used during construction
ARCO	Arco Solar Incorporated
BOS	balance of system
CC	combined cycle
CRF	capital recovery factor
CT	combustion turbine
DC	direct current
DOE	Department of Energy
EC	competing energy costs
EPRI	Electric Power Research Institute
EVA	ethylene vinyl acetate
FCR	fixed charge rate
JPL	Jet Propulsion Laboratory
O&M	operation and maintenance
PCS	power conditioning system
PV	photovoltaic
PVB	polyvinyl butyral
R&D	research and development
SMUD	Sacramento Municipal Utility District
STC	standard test conditions

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SECTION 1

INTRODUCTION AND SUMMARY

1.1 OVERVIEW

The Department of Energy (DOE) National Photovoltaics Program provides support for the development of photovoltaic (PV) technology. To guide this research program, DOE establishes technical goals for the research activity needed to make central station photovoltaic power systems competitive with conventional energy technologies. DOE has adopted a revenue requirements methodology for setting technical goals and planning targets. This study uses that methodology to examine the possible trade-offs between the PV system cost and efficiency parameters which meet program goals, and their sensitivity to geographical location and tracking configuration.

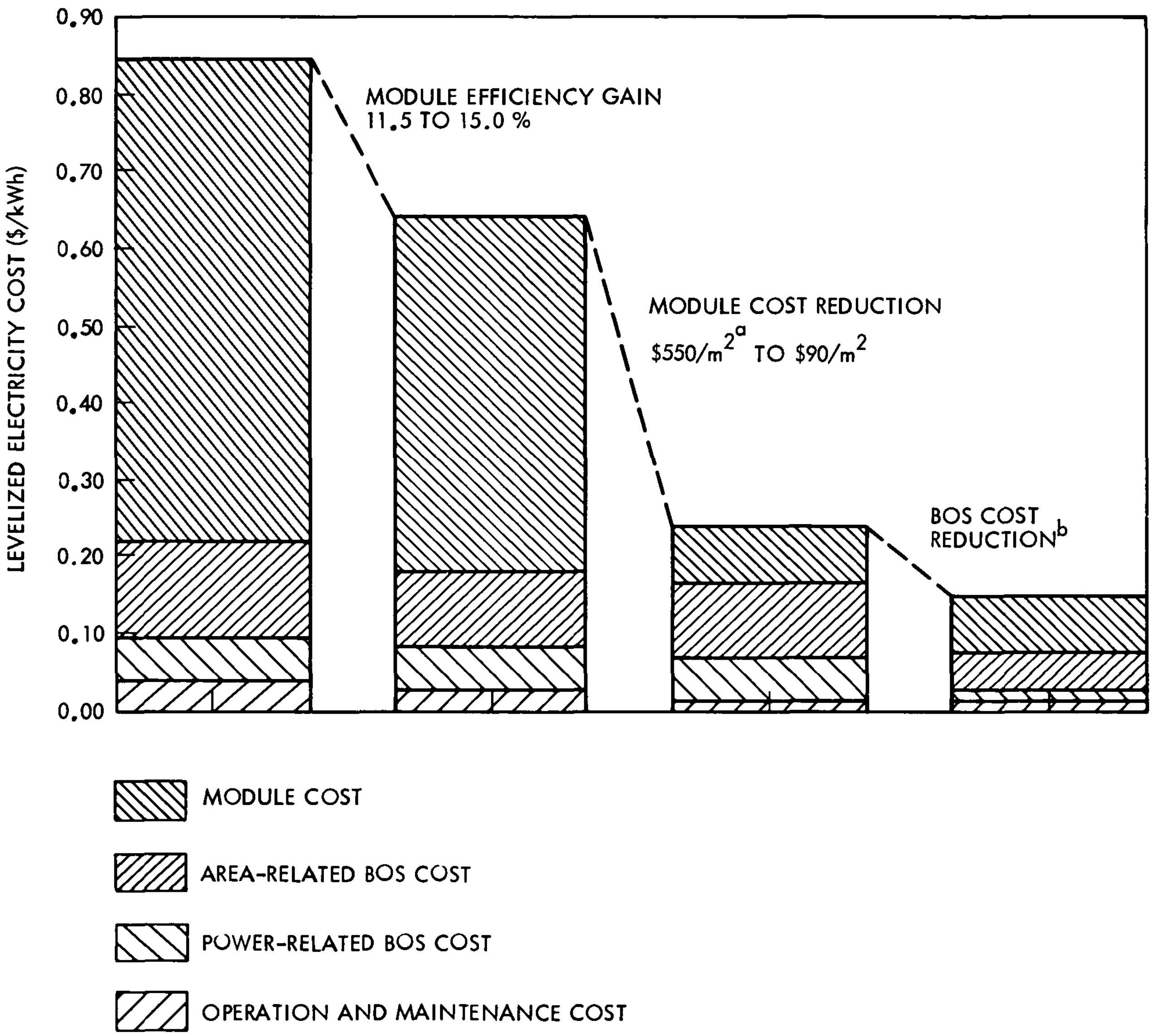
The sensitivity study shows the importance of achieving the efficiency and durability goals for PV systems as set out in the DOE *Five-Year Research Plan* (Reference 1). These goals are shown to be very sensitive to assumed operating conditions for the modules and to competing energy costs (EC), both of which change significantly with geographical location. Furthermore, trade-offs exist between PV system cost and efficiency parameters in reaching program goals. The choice of a fixed or tracking configuration for the module installation also has important implications for the competitiveness of photovoltaics with conventional energy technologies.

1.2 SENSITIVITY STUDY FINDINGS

The goals of the DOE *Five-Year Research Plan* define a path for the development of a competitive PV technology. Beginning with today's PV systems, Figure 1 shows how the realization of these goals will produce a competitive technology. Improved efficiency, module cost reduction, and balance of system (BOS) cost reduction all play important roles in reaching the objective. Combined, they are projected to bring about a reduction in the cost of energy produced by PV systems from today's $0.85/kWh to $0.15/kWh, measured as the levelized cost of electricity[1] over the plants' life.

Parameters other than those illustrated in Figure 1 are also important to PV technology development. Reducing module degradation rates is one good example. Other areas of interest are the trade-offs that exist between program goals. An examination of these sensitivity questions lead to the following findings.

[1] In this study, all levelized costs are in nominal rather than real terms. Nominal levelization closely approximates utility (inflation included) accounting practices; and it is the method which DOE has adopted for national program planning. The difference between nominal and real levelized costs is discussed in Appendix C.



[a] COST ESTIMATE BASED ON THE MOST RECENT ARCO SALES TO SACRAMENTO MUNICIPAL UTILITY DISTRICT (SMUD) (REFERENCES 2, 3, 4 AND 5).

[b] INCLUDES THE REDUCTION OF AREA-RELATED BOS COST FROM $115/m² TO $58/m² AND POWER-RELATED BOS COSTS FROM $600/kW TO $150/kW.

Figure 1. Reaching $0.15/kWh Program Objective (1982 Dollars)

1.2.1 Tracking Configuration

One-axis tracking is an important technical option for reaching program goals. For 15% efficient modules, allowable module costs are a minimum of 20% lower for fixed and two-axis tracking configurations. At current commercial module costs, however, two-axis tracking is optimal.

1.2.2 Solar Insolation and Competing Energy Costs

(1) Solar insolation and EC are specific to geographical location. As a result, the selection of specific PV system cost and efficiency goals limits system applications to certain geographical markets. Setting higher goals for system efficiency and reductions in the cost of system components ensures a large market for PV. However, increased R&D resources will be required for program success.

(2) Appropriate values for program planning are an energy cost goal of \$0.15/kWh and annual insolation values of 2000, 2400, 2600 kWh/m^2/yr (fixed array, one-axis tracking, and two-axis tracking systems, respectively). With DOE program goals of \$90/m^2 for module cost and 15% module efficiency, one-axis tracking systems will be competitive in several southern geographical markets and other locations with high conventional energy costs.

(3) Although the National Photovoltaics Program goals are defined using specific values for annual solar insolation, high competing energy costs in some local markets will make photovoltaics attractive despite significantly lower insolation. Using typical insolation and EC values for each location, Figure 2 shows how high annual insolation in Phoenix raises allowable module cost (maximum that can be paid for modules without system energy costs exceeding goals) well above the \$90/m^2 program goal for a 15% efficient module, despite low EC. In comparison, Miami just falls below the program goal at \$88/m^2 because of lower insolation. Insolation levels are even lower in Long Island than Miami, but as Figure 2 indicates, higher EC raises allowable module costs to program goal levels.

1.2.3 Module Cost and Efficiency Trade-offs

(1) High efficiency (e.g., greater than 15%) is neither necessary, nor is it alone sufficient, for economically viable systems (Figure 3). Technologies, such as thin-films, may provide relatively low cost, low efficiency modules that result in competitive system energy costs. For example, the lower curve in Figure 3 indicates that 10% efficient modules would meet program goals for system energy cost if they could be produced for \$30/m^2. In contrast, many current lower bound estimates for crystalline silicon solar cell production costs are greater than \$90/m^2, which

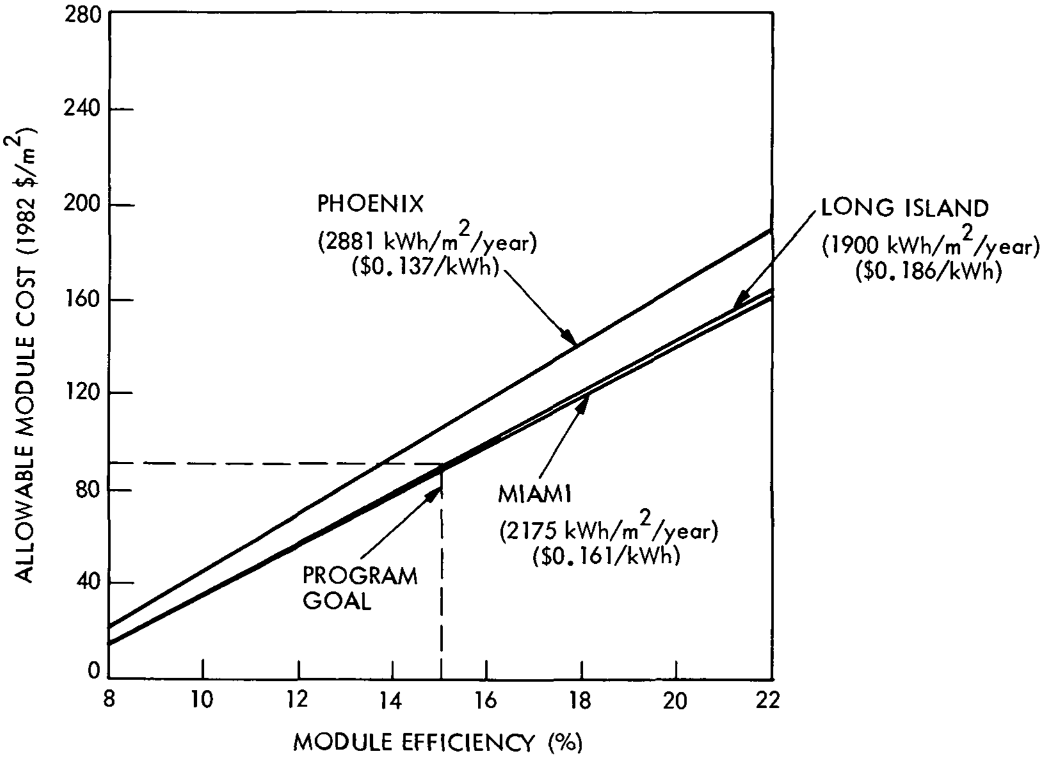


Figure 2. Importance of Insolation and Competing Energy Costs (1982 Dollars)

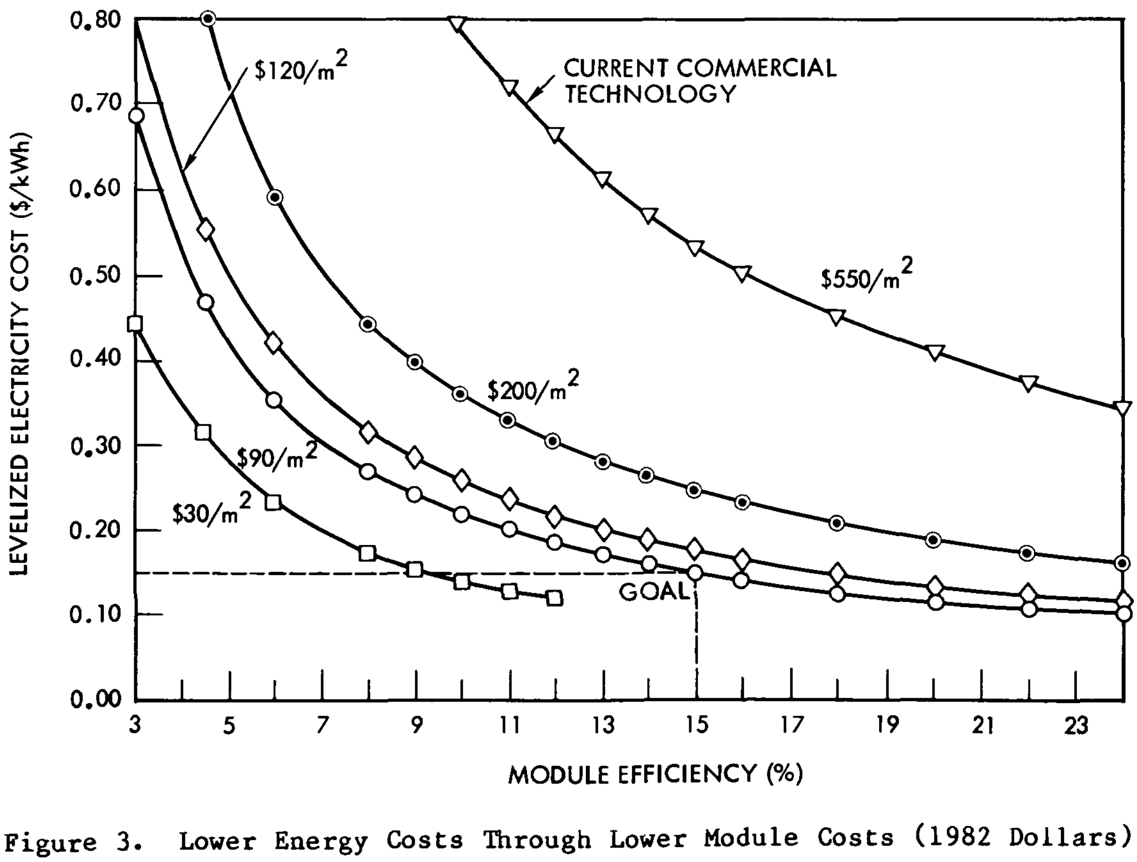


Figure 3. Lower Energy Costs Through Lower Module Costs (1982 Dollars)

indicates that some efficiency improvements above program goals may be required. Accordingly, the program should remain flexible in its research program to exploit the trade-offs between these parameters.

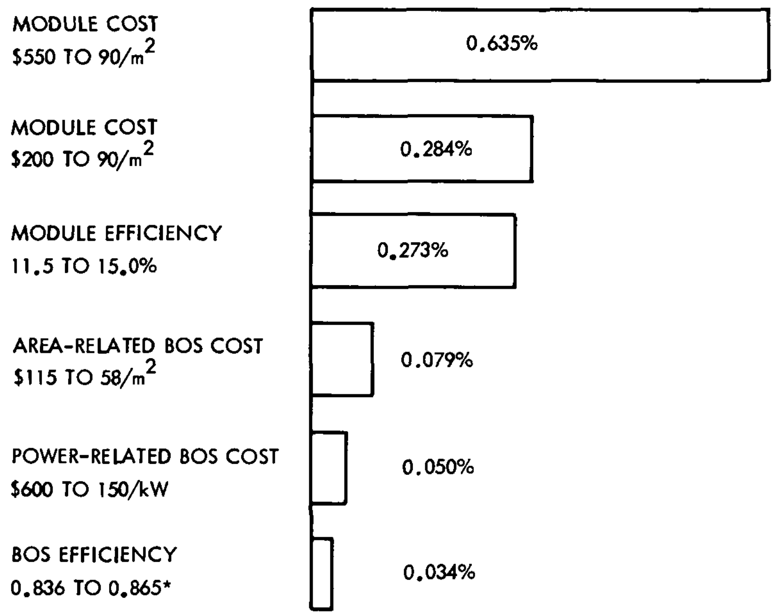
(2) Further reductions in module cost are necessary for developing economically viable systems. For current commercial module costs of $\$550/m^2$, Figure 3 shows that increases in module efficiency up to 24% and above are not sufficient to reduce system energy costs to a competitive level, \$0.15/kWh. The same conclusion can be drawn for modules costing $\$200/m^2$, which corresponds to estimated production costs using state-of-the-art technology and scaled-up production facilities. However, a module costing $\$120/m^2$ would be competitive at an efficiency of approximately 18%.

1.2.4 PV System Parameters and System Energy Cost

(1) Research advances in several areas of PV technology can lead to significant improvements in the competitiveness of the technology. Figure 4 shows how PV system energy costs decline in response to a 1% reduction in the gap between current technology and the program goal. For example, a 1% closing of the gap in module cost, $\$1.10/m^2$, results in a 0.284% reduction in PV system costs. This example uses a much lower value for current module costs, $\$200/m^2$ rather than the $\$550/m^2$ used in Figure 1. Modules can be purchased commercially for $\$550/m^2$. However, studies at the Jet Propulsion Laboratory (JPL) (Reference 6) indicate that they could be produced for $\$200/m^2$ using the best available technology and large scale production facilities. The focus of R&D efforts are on improving the best available technology, so $\$200/m^2$ will be used for the remainder of this report.

Closing the gap in module efficiency was found to be almost equally effective in improving the technology's competitiveness as reductions in module cost. Improvements in area-related BOS cost and power-related BOS cost would only be a half or a third as effective as module efficiency gains in moving the PV technology toward its goals. Nevertheless, their importance cannot be overlooked. If the research outlook indicated that dollars spent on BOS research would be two or three times more effective, these areas would belong on an equal standing with module efficiency research. (Obviously, other considerations must also enter the process of setting research priorities.)

(2) The baseline assumptions for this study are given in Table 1. The information in the table is sufficient to calculate the energy costs of fixed, one-axis and two-axis PV systems.



*THE BOS EFFICIENCY VALUES ARE APPROPRIATE WHEN CALCULATING LEVELIZED BUS BAR ENERGY COSTS UNDER THE SPECIFIC ASSUMPTIONS OF THIS STUDY. THEY SHOULD NOT BE INTERPRETED AS THE REAL RANGE OF BOS EFFICIENCIES. THE DERIVATION OF BOS EFFICIENCIES, INCLUDING DEGRADATION, IS GIVEN IN APPENDIX B.

Figure 4. PV System Cost Sensitivity (Response to 1% Closing of Gap Between Current Technology and Program Goals, 1982 Dollars)

A number of revisions of this baseline case have been made since the original publication of the Five-Year Research Plan. The principal implication of these revisions is an increase in allowable module costs for flat-plate systems from a range of $\$40$-$75/m^2$ as found in the Five-Year Research Plan to $\$90/m^2$. The crystalline silicon solar cell technologies, which have relatively high manufacturing costs, are now more likely to fall in the range of allowable module costs.

(3) The indirect cost multiplier, which is a markup on capital costs for construction expenses other than labor and materials, was set at the same level (1.5) used in the Five-Year Research Plan. A review of the information used to estimate this parameter indicated a wide range of plausible values. Sensitivity of system energy costs and technical goals to this parameter make its value an important consideration.

(4) The fixed charge rate which provides for the recovery of capital investment is reduced from the 0.180 used in the Five-Year Research Plan to 0.153. Improved tax treatment in

Table 1. Technical and Economic Parameters for PV System Evaluation (1982 Dollars)

Module Area Cost	\$90/m^2
Module Efficiency at STC*	15%
Nominal Levelized Energy Cost	\$0.15/kWh
Annual Insolation:	
Fixed Array	2000 kWh/m^2/yr
One-Axis Tracking	2400 kWh/m^2/yr
Two-Axis Tracking	2600 kWh/m^2/yr
BOS Efficiencies:	
Dirt	0.97
Degradation	0.963
Mismatch	0.99
Other (Includes shadowing, PCU efficiency, AC and DC wiring losses)	0.935
Cumulative BOS Efficiency	0.865
Area-Related BOS Cost:	
Fixed Array	\$50/m^2
One-Axis Tracking	\$58/m^2
Two-Axis Tracking	\$90/m^2
Power-Related BOS Cost	\$150/kW AC
Annual O&M Cost:	
Fixed Array	\$1.10/m^2
Tracking	\$1.40/m^2
Indirect Cost Multiplier	1.5
Fixed Charge Rate	0.153
Capital Recovery Factor	0.129
Present Worth Factor	18
General Inflation Rate	8.5%
Nominal Discount Rate	12.5%

*Throughout this report, all module efficiencies are measured with respect to standard test conditions, 1000 kWh/m^2/yr irradiance and 25°C cell temperature. A 0.88 temperature adjustment factor, TC, is used in the equation presented in Table 2 to compensate for actual cell temperatures.

terms of the allowed rate of depreciation accounts for the change. An acceleration of the rate of depreciation allowed on investment, income tax credits, or a reduction in the tax rate will lower the fixed charge rate. Reductions in the fixed charge rate work in favor of PV systems relative to conventional generation technologies because of the greater capital intensity of PV technology.

(5) Reflecting more recent studies of operation and maintenance (O&M) costs, the estimate has been reduced from $\$2.28/m^2/yr$ for flat-plate systems and $\$2.69/m^2/yr$ for tracking systems to $\$1.10/m^2/yr$ and $\$1.40/m^2/yr$, respectively. O&M costs are only a small fraction of PV system costs, but wide variations in module replacement rates were found to have significant cost implications.

SECTION 2

THE FRAMEWORK

2.1 PURPOSE

The successful development of any new technology such as PV depends on its economic competitiveness with other technological options. In order to provide a framework for the evaluation of PV research and technology development, the DOE has adopted a revenue requirements methodology for calculating the cost of energy produced by a PV system (see Reference 1). DOE has also set a levelized electricity cost goal of $0.15/kWh for energy produced by central station PV systems. This energy cost is midway between the expected costs of new oil and new coal generation, and is comparable to the cost of new coal generation at capacity factors typical of intermediate load generation (References 7 and 8). The energy cost goal, therefore, represents widespread commercial viability for PV systems.

The cost of energy produced by a PV plant is a function of many parameters, including the cost of the plant, O&M costs, meteorological conditions, financial factors, and technological performance. This report investigates the sensitivity of the PV system energy cost to changes in these parameters and the trade-offs between various cost components consistent with a given energy cost goal. The implications of these changes and trade-offs for the National Photovoltaics Program are also examined.

The purpose of this analysis is to help DOE and industry develop commercially viable central station PV systems. Given the energy cost goal, it is important to analyze the available trade-offs between PV system components so that component goals can be established in a way that increases the likelihood of overall program success. Furthermore, by determining the sensitivity of system energy cost to changes in parameter values, the most promising opportunities for PV research and development can be identified. This report shows that substantial progress can be made toward achieving the energy cost goal by taking advantage of the economic and technical opportunities and trade-offs that exist for low-cost PV systems. Specific parameter values and technical goals for planning purposes are also reviewed based on the results of recent research and field studies.

Since module cost and efficiency are the major components of PV energy cost at this time, and because module development is the most promising and active research area, the analysis emphasizes trade-offs between module cost and module efficiency under different economic and technical conditions. In general, this study discusses module cost and performance characteristics in terms of "allowable" costs and efficiencies, which are the costs and efficiencies that are consistent with a given energy cost goal.

2.2 APPROACH

Life-cycle energy cost is an appropriate measure for evaluating PV research progress and economic viability. With this approach, the future value of the new technology can be used directly in the process of setting

research and development priorities. Furthermore, "comparing conceptual designs and cost estimates of a new technology with those of a currently available technology gives insight into the cost incentives and technical issues associated with the new technology" (Reference 9).

Annualized life-cycle costs of a central station PV generating system can be calculated using the expression in Table 2. The left side of the expression summarizes the annual capital and operating needs of the system. The right side of the equation summarizes the value of the output, where EC measures energy cost and the remainder of the expression represents annual output. The cost calculated with this expression is the cost of electricity that the system will be able to compete with. If the cost is well above the expected cost for conventional generating plants, then significant use of the technology by electric utilities cannot be expected. Conversely, if the cost is below what is projected for conventional generating plants, then electric utilities can be expected to include PV in their investment plans[2]. (Of course, factors other than cost will also influence their decisions; see Reference 8.)

With the aid of this expression, several areas of uncertainty affecting the future of the technology can be explored. One area is the trade-offs between the parameters which determine the cost of the PV system. For example, how much of a reduction in area-related BOS cost ($MSQBS) is needed to offset an increase in module cost ($MSQMD)? This is easily calculated using the equation in Table 2 by holding the remaining parameters constant, and finding the combination of $MSQMD and $MSQBS that maintain the equality. Another important area of uncertainty is the cost of competing energy. Holding everything else unchanged, energy cost can be increased and the allowable increase in module cost calculated. The expression for calculating life-cycle energy cost includes three financial parameters: the fixed charge rate (FCR), the present worth factor (G) and the capital recovery factor (CRF). These parameters can be varied to determine the consequences for another parameter such as module cost. However, considerable care has to be taken when changing the financial parameters. The energy cost for competing technologies may also be affected by the same financial parameters.

2.3 DATABASE

In the process of investigating the sensitivity of individual parameters, an extensive database was constructed. The database includes values used for the technical parameters found in the expression for annualized life-cycle energy cost, and values appropriate for characterizing solar energy availability, EC, and financial conditions. The values settled upon for this study were given previously in Table 1.

[2]Papay, L.T., Southern California Edison Co., "The Electric Utilities and Photovoltaics: Financing and Integration," Rosemead, California (prepared for 2nd International Conference on Photovoltaic Business Development, Geneva, Switzerland, May 18, 1983).

Table 2. Revenue Requirements Methodology

$$\left(\$MSQMD + \$MSQDS + \frac{KWBS}{A}\right) INDC\cdot FCR + \$MSQOM\cdot G\cdot CRF = \frac{EC\cdot INSOL}{A\cdot PKI}$$

$MSQMD = module costs in $\$/m^2$

$MSQBS = balance of system area-related costs in $\$/m^2$

$KWBS = balance of system power-related costs in $/kW AC

INDC = indirect cost multiplier

FCR = annual fixed charge rate (includes the cost of debt and equity capital, taxes, allowable depreciation and tax credits)

$MSQOM = annual operation and maintenance costs in $\$/m^2$-yr

G = present worth factor for recurring O&M costs (function of cost escalation rate, discount rate and system lifetime)

CRF = capital recovery factor (a function of the discount rate and system lifetime)

EC = levelized cost of electricity in $/kWh

INSOL = annual insolation in kWh/m^2

A = 1/(TC•BOSE•EFF•PKI)*

*A is the plant aperture area required to generate 1kW of AC power at the busbar under typical operating conditions. A is a function of the effect of temperature on cell efficiency (TC), balance of system efficiency (BOSE), module efficiency (EFF), and average peak insolation (PKI) in kW/m^2 for the location.

The starting point for developing the set of parameters found in Table 1 was an Electric Power Research Institute (EPRI) investigation of PV system requirements (see Reference 7). The results of this EPRI study were used in the preparation of the Five-Year Research Plan. Since that time, several efforts have been made to revise and update these parameters and the Five-Year Plan energy cost equation, based on the latest research findings (Reference 10)[3,4]. Finally, the interim results of the sensitivity analysis were used to arrive at what are believed to be the most realistic goals for PV

[3]Borden, C., Jet Propulsion Laboratory, "Recommended Parameter Values for the Five-Year Research Plan," Photovoltaics Program Memo PAIC:CSB:720-84-1697, Pasadena, California, February 13, 1984.

[4]Crosetti, M., Jet Propulsion Laboratory, "The Indirect Costs of Central Station Photovoltaic Power Plants," JPL Memo 311.3-1429/2564E, July 19, 1985.

program research. The sensitivity analysis made it possible to explore the trade-offs between different system parameters made practical by recent technology improvements.

Sensitivity studies for individual parameters found in the remaining sections of this report include discussions of how the value for each parameter was attained. This information is often relevant to the range of sensitivities that should be explored. In addition, the information is often useful in deciding upon which trade-offs need to be considered.

SECTION 3

KEY TRADE-OFFS AND COMPETING ENERGY COSTS

3.1 DIRECTION

Significant gains in PV module efficiency and cost are required to make PV competitive with conventional generating systems in central station applications. Goals set by the National Photovoltaics Program in both areas represent major improvements over current technology. This is true both in terms of what is commercially produced today and what could be produced using the best available technology. Fortunately, the goals are relaxed somewhat by the fact that exceptional gains in one area such as module efficiency can be traded off against less success in the area of module cost. Furthermore, additional trade-offs exist with the goals set for the remaining elements of the PV system, BOS cost and efficiency. These critical sensitivities are the first topic covered in this section.

The competitiveness of a PV system in a central station application depends to a large extent on geographic location (e.g., insolation and EC costs), and the outlook for conventional energy cost escalation. Higher insolation values, like those found in the desert Southwest, and higher conventional energy costs, like those found in the Northeast, work in favor of PV systems. The selection of a tracking configuration, fixed, one-axis, or two-axis tracking, also influence the economics of PV systems in central station applications. The combination of a good geographic location, the prospect of rapidly escalating conventional energy costs, and the selection of the best tracking option can greatly improve PV system economics. The remainder of this section looks at how each of these factors affect the goals that have been set for the National Photovoltaics Program.

Because of recent reductions in estimates of area-related BOS costs for one-axis tracking equipment, these systems seem to be the most economically promising over a large range of module efficiencies. Consequently, most of the analysis is concerned with one-axis systems. However, fixed array and two-axis systems are analyzed in the section on annual insolation because the values of this parameter depend on the tracking configuration of the system. In particular, high cost modules, such as those commercially available today, often produce the cheapest energy when used in systems with two-axis tracking.

3.2 PV SYSTEM COST SENSITIVITY

The cost of PV modules and their efficiency are the two most critical elements of system energy cost. Not only is a large portion of the life-cycle energy cost related to these factors, but they also exhibit the greatest potential for improvements through research. Current commercial

module costs are $\$550/m^2$ for 11.5% efficient modules.[5] The DOE target is $\$90/m^2$ for a 15% efficient module which may be achievable with several PV technologies in the 1990s. Progress in lowering module costs and raising efficiency is essential if central station PV systems are to become commercially viable on a large scale. Competitive energy costs are the only other parameter that influences the prospects for PV to such an extent.

The sensitivity of system energy cost to changes in several areas of PV system technology are illustrated in Figure 5. The top chart shows how a percentage change in specific system parameters with all other parameters held at recommended goal levels (see Table 2) impacts system energy cost. For example, if module costs fall 40% short of the recommended goal of $\$90/m^2$, the result would be approximately a 20% increase in system energy costs. In comparison, if module efficiency falls 40% short of the goal value of 15%, system energy costs rise 60%. System energy costs are just as sensitive to BOS efficiency, but this value would not be expected to experience this large of percentage variation from recommended goal values. Figure 5 also shows that PV system energy costs will be least affected on a percentage basis by area-related and power-related BOS cost variances.

The relationships between system energy cost and changes in system parameters depend on the frame of reference chosen. In the top chart, changes in the absolute level of each parameter were considered, beginning at recommended goal levels. The lower chart shows how these sensitivities change if the frame of reference is moved to system parameters achievable with current technology, and parameter changes that would lessen the gap between current technology and program goals. For example, modules could be produced for as little as $\$200/m^2$ today (see Reference 6) compared to the current program objective of $\$90/m^2$. If that gap were closed by 40%, $\$44/m^2$ (40% of difference between $\$200/m^2$ and $\$90/m^2$), system energy cost would be reduced by approximately 25%. The same percentage improvement in module efficiency is not nearly as effective in reducing system energy cost, reflecting the smaller disparity between currently achievable technology (11.5%) and the goal for the program (15%). Obviously, these sensitivities will also depend on the technology being examined.

PV system energy cost sensitivities, including those used in the construction of Figure 5, are presented in Table 3. The sensitivity of system energy cost to various cost categories are given first. For example, a 1% reduction in module cost from current state-of-the-art levels ($2 for modules costing $\$200/m^2$) will lower system energy cost by 0.502%. In comparison, a 1% reduction in the gap between current technology and the program goal lowers system energy cost by 0.305%. The relationship of each of these cost categories to system energy cost is linear. Therefore, a 10% increase in module cost from the current level increases the system energy cost by 5.02%.

[5] The efficiency number is based on ARCO Solar Incorporated (ARCO) M-53 modules. The cost figure is based on ARCO module sales to SMUD (see References 2, 3, 4 and 5).

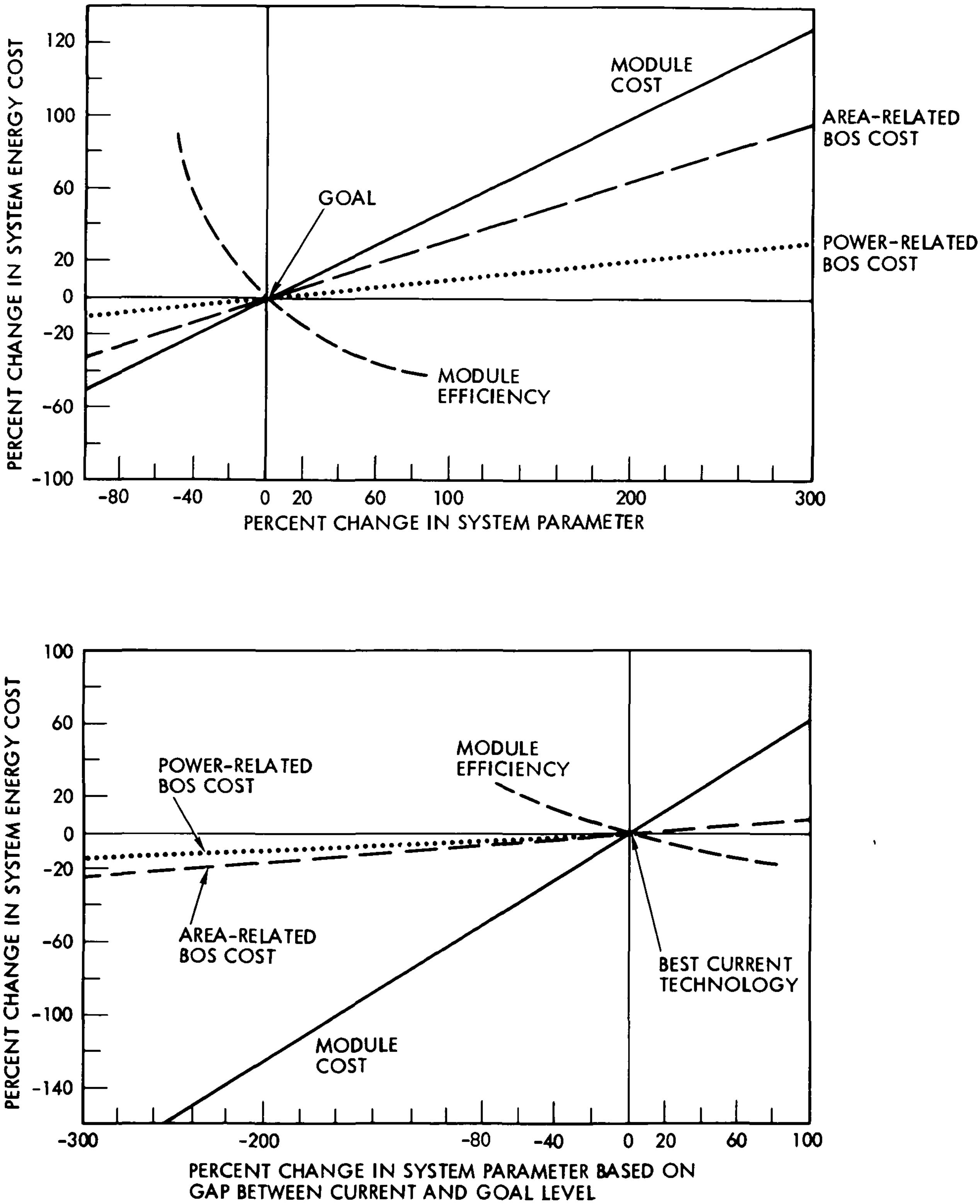


Figure 5. PV System Cost Sensitivity to Changes in System Parameters

Table 3. PV System Cost Sensitivity to Changes in System Parameters

	Resulting Percentage Change in PV System Cost			
1% Change in:	Based on Current Values*	Goal Values*	Gap Between Values	
Module Cost	0.502	0.511	0.305	
Area-Related BOS Cost	0.323	0.294	0.146	
Power-Related BOS Cost	0.096	0.125	0.094	
Indirect Cost Multiplier	0.921	0.930	0.269	
O&M Cost	0.079	0.070	0.044	
	Based on Current Values*	Goal Values*	Gap Between Values	
Percent Change in Efficiency Parameter:	Module or BOS Efficiency	Module or BOS Efficiency	Module Efficiency Only	BOS Efficiency Only
+60%	-32.8	-33.9	-13.5	-1.8
+40	-25.0	-25.8	- 9.5	-1.2
+20	-14.6	-15.1	- 5.0	-0.6
+10	- 8.0	- 8.2	- 2.6	-0.3
-10	9.7	10.0	2.7	0.3
-20	21.9	22.6	5.7	0.6
-40	58.4	60.3	12.1	1.2
-60	131.3	135.7	19.6	1.9

*The current and goal values for each parameter are: module cost ($200-$90/m^2), area-related BOS cost ($115-$58/m^2), power-related BOS cost ($600-$150/kW), indirect cost multiplier (2.11-1.50), O&M cost ($3.8 to $1.4/$m^2$), module efficiency (11.5 to 15.0%), and BOS efficiency (83.6 to 86.5%).

The relationship between changes in module efficiency or BOS efficiency and system energy cost is nonlinear. Accordingly, several individual sensitivities are given in Table 3 to show how system energy costs respond over a fairly wide range of changes. When considering the gap that needs to be closed between current values and program goals, separate values are needed for module and BOS efficiency. The values in this case are different because the gap to be closed in BOS efficiency is relatively smaller than for module efficiency. Closing the gap in module efficiency will lower system energy cost more than closing the gap in BOS efficiency.

For a given percentage improvement from current values, system energy costs are most sensitive to module and BOS efficiency changes. System efficiency affects not only the total module costs of a PV system, but total area-related BOS costs and annual O&M costs as well. (Lower efficiency requires more module area to maintain a given plant output rating; therefore, the amount spent on modules, area-related BOS items, and O&M will increase.) In comparison, changes in module cost do not affect the total amounts spent on other plant items.

3.3 ENERGY COST GOAL

DOE has adopted a $0.15/kWh cost goal for energy produced by PV plants. This goal represents the cost of other generating sources with which PV must compete to be commercially viable. The goal is calculated in terms of nominally levelized busbar energy cost; real levelization yields an equivalent goal of $0.065/kWh (1982 dollars). Appendix C discusses the distinction between real and nominal levelization.

Along with module cost and efficiency, the cost of competing generation options is one of the most important determinants of whether or not PV systems ultimately make a significant contribution to national energy requirements. Figure 6 shows the combinations of module cost and efficiency allowed under different competitive energy costs. Clearly, the economic prospects for PV systems depend on the future costs of other generating options as well as on PV R&D progress.

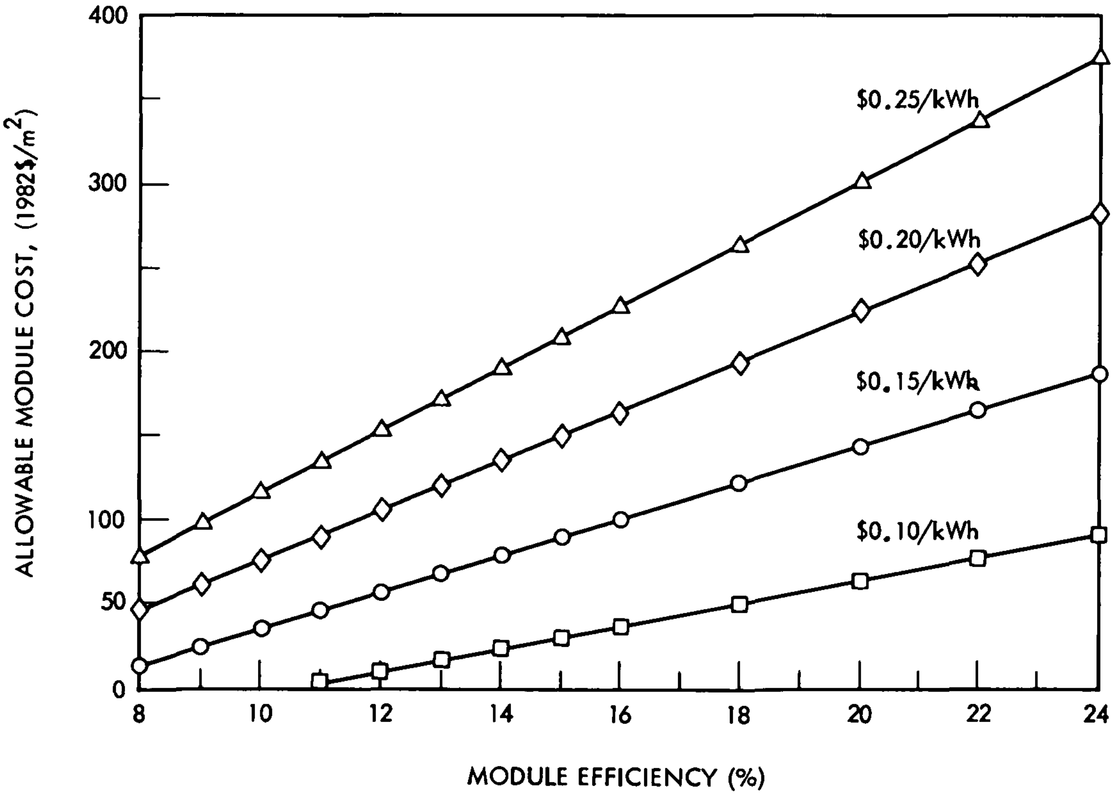


Figure 6. Allowable Module Costs and Efficiency Trade-offs for Various Competing Energy Costs (1982 Dollars)

The \$0.15/kWh goal corresponds to a large penetration for PV into the peaking and intermediate load energy markets in areas with sufficient insolation. A higher goal would represent a smaller market as there would be fewer cases in which PV would be competitive. An appropriate goal is one that represents the desired market for PV. As EPRI points out, "Technology goals must be set in conjunction with an estimate of the desired market" (see Reference 8). In this respect, DOE's energy cost goal, insolation levels for planning, and energy cost equation are useful for determining the various effects of market size on technical goals.

If less ambitious market penetration is desired for the research program, then a higher value should be adopted. Scenarios of higher priced coal and residual fuel oil generation suggest an energy cost goal of \$0.20/kWh. This change would have a tremendous impact on module cost and efficiency goals as indicated in Figure 6.

Before PV systems will be considered in electric utility expansion plans, they will have to be competitive on a cost basis with the conventional generating options open to the utility. Earlier studies have shown that output of PV systems are best suited for meeting the intermediate load requirements of electric utilities. In today's market, the lowest cost conventional option for capacity expansion is coal. (Nuclear power was not considered because of legal and environmental problems confronting the technology.) A coal-fired plant meeting the intermediate load requirements of a utility would have a capacity factor of about 0.30. Therefore, competing energy costs have been estimated on the basis of a new coal-fired plant operating with a capacity factor of 0.30.

The revenue requirements of a future coal plant depend on a set of relatively uncertain parameters that vary with location. The cost of constructing a coal-fired plant and the cost of the coal burned depend on the region of the country where the plant is located. Also, life-cycle energy costs are quite sensitive to cost escalation rates assumed for fuel and plant investment. These considerations can be incorporated into a life-cycle costing methodology similar to the one that was used for calculating PV system energy costs.

Different possible life-cycle energy costs for coal-fired plants meeting intermediate load requirements are given in Table 4. The table illustrates how these cost estimates vary by region of the country and different assumed escalation rates for capital and fuel costs. The cost estimates in this table are based on capital cost and O&M cost estimates taken from the EPRI <u>Technical Assessment Guide</u> (see Reference 9). Fuel costs were derived from industry journals (Reference 11).

The energy cost values in Table 4 indicate that PV systems will be competitive in the Northeast if program goals are met and sufficient insolation is available. For the Pacific and Rocky Mountain regions where insolation is not exceptional, PV systems would be competitive only where escalation rates for capital and fuel costs are projected to be high enough. Figure 7 gives some perspective on how the energy cost goal for the National Photovoltaics Program compares to the outlook for coal-fired generation costs, serving as intermediate load capacity. Although the figure alone cannot be

Table 4. Levelized Costs of Coal-Generated Power for Meeting Intermediate Loads (Dollars/kWh)

Region	Capital Cost Escalation, %	Fuel Cost Escalation, %			
		0	1	2	3
Northeast*	0	0.153	0.167	0.183	0.203
	1	0.159	0.172	0.189	0.209
	3	0.173	0.186	0.202	0.222
	5	0.188	0.201	0.218	0.238
Pacific*	0	0.119	0.125	0.134	0.144
	1	0.125	0.132	0.140	0.150
	3	0.139	0.146	0.154	0.164
	5	0.156	0.162	0.170	0.180
Rockies*	0	0.111	0.116	0.122	0.130
	1	0.117	0.122	0.129	0.136
	3	0.132	0.137	0.143	0.151
	5	0.148	0.153	0.159	0.167

*The following conditions were assumed for each region, based on Reference 8.

	Northeast	Pacific	Rockies
Fixed O&M $/kW/yr	16.1	14.5	14.5
Variable/Consumables O&M $/kWh	0.0037	0.0024	0.0024
Capital Cost $/kWh	1090	1150	1150
Fuel Cost $/Ton (Reference 10)	52	26	20
Heat Rate kWh/Ton	2162	2162	2162
Working Capital Cost Markup	1.2	1.2	1.2

used to determine specific energy markets for PV, it gives some indication of the breadth of markets that would be available and how their number would be affected by capital and fuel escalation rates.

A smaller initial market for PV may be considered by adopting a cost goal based on competition with higher priced coal generation or with residual fuel oil generation. A recent study found that over 3,000 MW of new oil and gas-fired generating capacity is planned for the next ten years (Reference 12). Table 5 presents residual oil combustion turbine energy cost scenarios for different fuel cost trends with conventional and advanced plant designs. The combustion turbine is typical of peaking plants. Table 5 also presents energy cost scenarios for both conventional and advanced residual oil combined cycle plants, which are intermediate load generators.

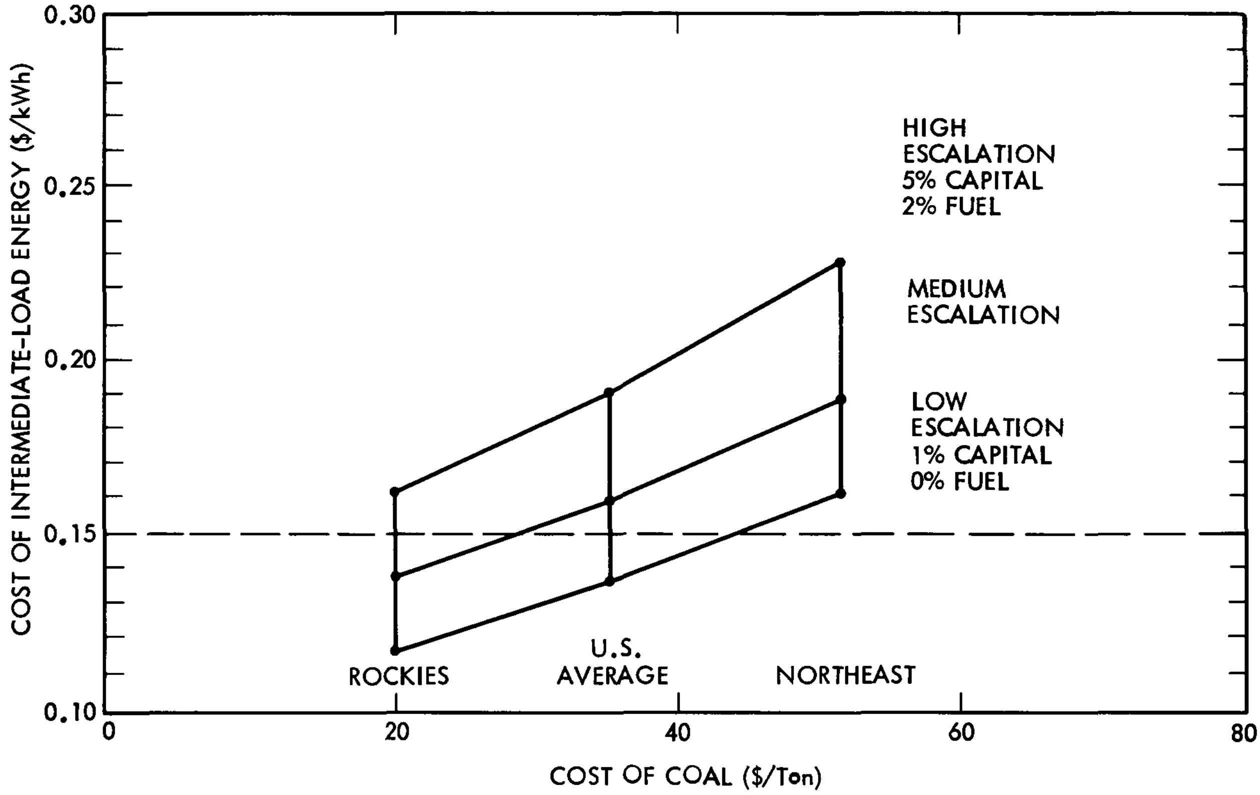


Figure 7. The Outlook for Intermediate Load Energy Costs and Achieving the PV Program Energy Cost Goal (1982 Dollars)

In summary, the cost of competing energy in a particular utility application can vary significantly from the national program goal of $0.15/kWh. For example, regional differences exist in the cost of electricity from new coal plants. Utilities are likely to vary in their opinion as to what the cost of coal-generated electricity will be, based on their outlook for fuel and capital cost increases. Also, some utilities may be considering combined cycle oil-fired plants for intermediate load capacity. In applications where PV will be serving peak load requirements, the cost of new combustion turbine plants enter the picture. The cost of electricity from these generating technologies is also sensitive to the outlook for capital and fuel cost escalation.

3.4 INSOLATION

Insolation values at a particular geographic location combine with the outlook for competing energy costs to determine the economic viability of a PV system. Insolation available on an annual basis can vary by as much as a factor of two between different locations in the United States, although the differences between most locations is considerably smaller. PV systems will

Table 5. Levelized Costs of Energy Generated by Combustion Turbine and Combined Cycle Oil-Fired Generators (Dollars/kWh)

Capital Cost Escalation (%)	Fuel Cost Escalation (%) -1	0	1	2
Conventional Oil Combustion Turbine*				
0	0.186	0.226	0.273	0.332
1	0.187	0.227	0.274	0.333
3	0.191	0.230	0.277	0.336
5	0.194	0.234	0.281	0.340
Advanced Oil Combustion Turbine*				
0	0.171	0.206	0.249	0.302
1	0.172	0.208	0.250	0.303
3	0.176	0.212	0.254	0.307
5	0.180	0.216	0.258	0.311
Conventional Combined Cycle Oil*				
0	0.138	0.163	0.192	0.229
1	0.141	0.166	0.195	0.231
3	0.147	0.172	0.201	0.237
5	0.154	0.179	0.208	0.245
Advanced Combined Cycle Oil*				
0	0.128	0.150	0.175	0.207
1	0.131	0.153	0.178	0.210
3	0.137	0.159	0.185	0.217
5	0.145	0.167	0.192	0.224

*The following conditions were assumed for each technology based on Reference 8:

	Conventional CT	Advanced CT	Conventional CC	Advanced CC
Fixed O&M 1980 $/kW/yr	0.4	0.4	6.6	6.6
Variable/Consum. O&M 1980 $/kWh	0.0037	0.0037	0.0016	0.0016
Capital Cost 1980 $/kW	235	255	495	530
Fuel Cost 1980 $/mmBTU	5.15	5.15	5.15	5.15
Capacity Factor	0.261	0.267	0.3	0.3
Heat Rate BTU/kWh	14000	12600	8685	7620
Working Capital Cost Markup	1.2	1.2	1.2	1.2

become competitive with conventional energy resources at a much earlier stage in their development at locations with the best solar insolation. Figure 8 shows how the difference in insolation at several U.S. locations affects allowable module costs, assuming the same competing energy cost, e.g., \$0.15/kWh. The figure also shows how the baseline value for annual insolation (2400 kWh/m^2 for one-axis tracking systems) used in this study compares with insolation levels at several locations.

The baseline insolation values used in this study are 2000 kWh/m^2/yr (fixed array), 2400 kWh/m^2/yr (one-axis tracking), 2600 kWh/m^2/yr (two-axis tracking) and average peak insolation of 1 kW/m^2. The difference in the recommended insolation values associated with the various tracking configurations are consistent with measured data from across the nation[6] (Reference 13). The recommended two-axis tracking to fixed array insolation ratio is 1.3, and the recommended one-axis tracking to fixed array insolation ratio is 1.2. These differences are not as pronounced as they are in the very clear areas of the nation, such as Phoenix, nor are they as slight as one would find in the cloudier regions, such as Boston. The ratios employed here represent differences that would be expected in a typical area with fixed array insolation of 2000 kWh/m^2/yr.

Table 6 presents insolation values for different locations and system configurations. Insolation values for Phoenix are based on 10 years of measured data for all three tracking configurations (see Footnote 6). The baseline values encompass the greater Southwest as shown in Figure 9 (multiplying the MJ/m^2 contour levels by 101.4 gives insolation in kWh/m^2/yr). Values for Boston, Miami, and Fresno are based on TMY[7] data and are adjusted for anisotropic insolation (see Reference 13).

Tables 7, 8, and 9 depict the effects of these different insolation values on the allowable module costs for fixed plate, one-axis tracking, and two-axis tracking systems, respectively. Insolation at the Boston level would include most of the nation, and the Miami case would cover nearly one-half of the continental United States (Figure 9). Although these cases correspond to a large market area for PV electricity sales, the relatively poor meteorological conditions reduce allowable module costs to fairly low levels given the \$0.15/kWh energy cost goal.

The Phoenix case represents some of the highest available insolation in the country. Although this area provides excellent meteorological conditions and therefore allows for relatively high module costs, it does not support a large enough market for national planning purposes given the range of reasonable energy cost goals.

[6]Hulstrom, Roland, and Bird, Richard, Solar Energy Research Institute "Comparison of Isolation ... at Phoenix, Arizona," Interoffice Memo, R RA and I #1704, April 13, 1984. Also, Hulstrom, R., Solar Research Institute, "SERI Initial Results Comparing the Relative Amounts of Insolation ...;" Interoffice Memo, RA&I #1839, July 17, 1984.

[7]TMY data is an attempt to construct a typical meteorological year for 26 U.S. cities using data collected by the National Weather Service.

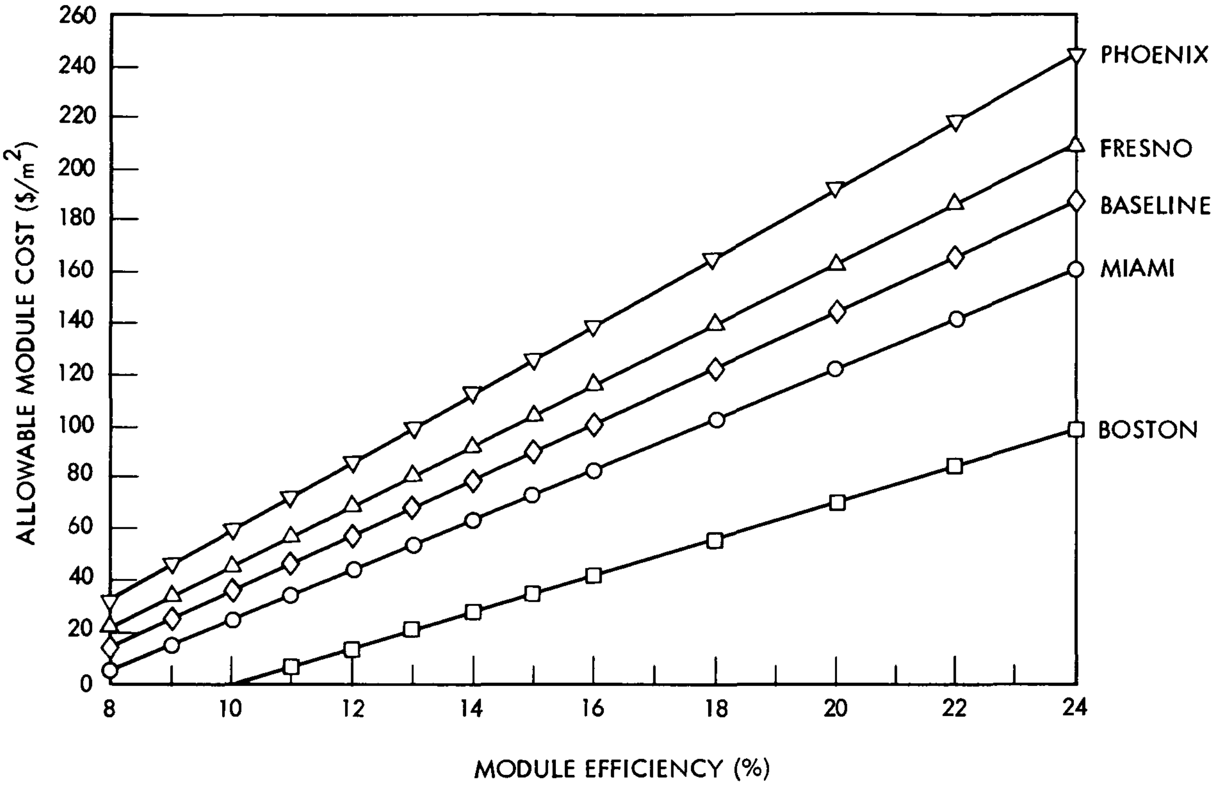


Figure 8. The Effects of Insolation Levels on Allowable Module Cost and Efficiency Trade-offs (1982 Dollars)

Table 6. Insolation Cases

	Boston	Miami	Baseline	Fresno	Phoenix
Fixed Array ($kWh/m^2/yr$)	1377	1797	2000	2141	2223
One-Axis ($kWh/m^2/yr$)	1665	2175	2400	2585	2881
Two-Axis ($kWh/m^2/yr$)	1843	2315	2600	2779	3198
Peak Insolation ($kWh/m^2/yr$)	0.67	0.8	1.0	1.0	1.0

The insolation values for Fresno would form a contour that encloses Arizona, New Mexico, Nevada, and parts of California, Texas, Colorado, and Utah. Approximately 10% of all U.S. electricity sales take place within this region (Reference 15). In comparison, the baseline case covers a region that includes over 14% of the nation's electrical energy demand. Of course, exporting power outside of these regions ("wheeling") could greatly increase the percentage of national demand potentially served by photovoltaics.

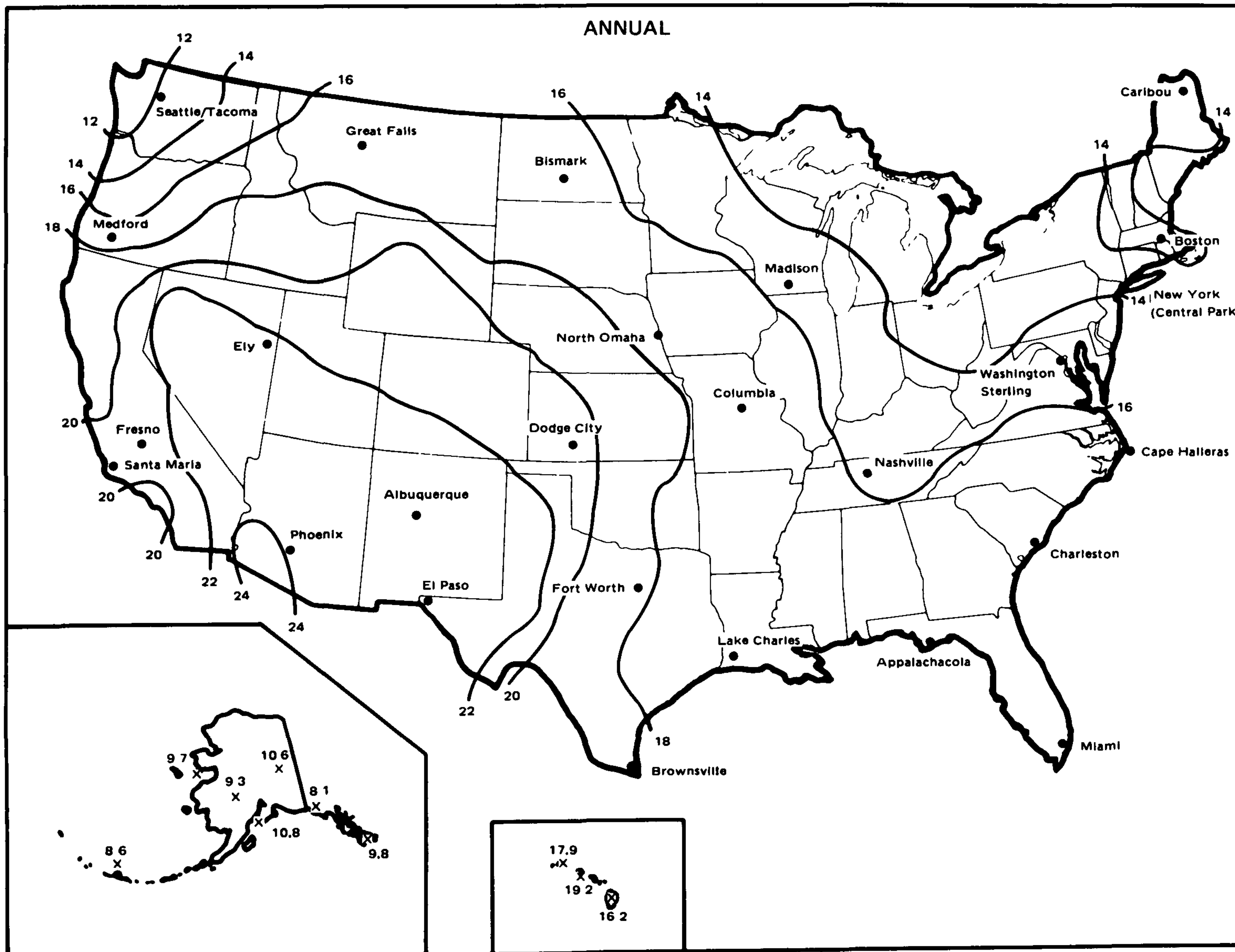


Figure 9. Average Daily Global Solar Radiation on a South-Facing Surface, Tilt = Latitude (MJ/m^2) (Reference 14)

Table 7. Allowable Fixed Array Module Cost (1982 Dollars/m^2)

	Boston	Miami	Baseline	Fresno	Phoenix
Annual Insolation ($kWh/m^2/yr$)	1377	1797	2000	2141	2223
Peak Insolation (kW/m^2)	0.67	0.8	1	1	1
Module Efficiency			Allowable Module Cost		
0.08	-12	3	9	15	18
0.09	- 6	11	18	24	28
0.10	0	19	27	34	38
0.11	6	27	36	43	48
0.12	12	35	45	53	58
0.13	18	43	53	63	68
0.14	24	51	62	72	78
0.15	30	59	71	82	88
0.16	36	67	80	91	98
0.18	48	83	97	110	117
0.20	61	99	115	129	137
0.22	73	115	133	148	157
0.24	85	132	150	167	177

Table 8. Allowable One-Axis Tracking Module Cost (1982 Dollars/m^2)

	Boston	Miami	Baseline	Fresno	Phoenix
Annual Insolation ($kWh/m^2/yr$)	1665	2175	2400	2585	2881
Peak Insolation (kW/m^2)	0.67	0.8	1	1	1
Module Efficiency			Allowable Module Cost		
0.08	-12	7	14	22	33
0.09	- 4	17	25	33	47
0.10	3	27	36	45	60
0.11	11	37	47	57	73
0.12	18	47	57	68	86
0.13	26	57	68	80	99
0.14	33	67	79	92	113
0.15	41	76	90	104	126
0.16	48	86	101	115	139
0.18	63	106	122	139	165
0.20	78	126	144	162	192
0.22	93	146	165	186	218
0.24	108	166	187	209	244

Table 9. Allowable Two-Axis Tracking Module Cost (1982 Dollars/m^2)

	Boston	Miami	Baseline	Fresno	Phoenix
Annual Insolation (kWh/m^2/yr)	1843	2315	2600	2779	3198
Peak Insolation (kW/m^2)	0.67	0.8	1	1	1
Module Efficiency			Allowable Module Cost		
0.08	-37	-19	-10	-3	14
0.09	-29	- 9	2	10	29
0.10	-20	2	14	23	44
0.11	-12	12	26	35	58
0.12	- 3	23	37	48	73
0.13	5	34	49	61	88
0.14	13	44	61	73	103
0.15	22	55	73	86	117
0.16	30	66	85	99	132
0.18	47	87	108	124	162
0.20	64	108	132	150	191
0.22	81	129	155	175	221
0.24	98	150	179	200	250

3.5 TRACKING CONFIGURATION

The tracking configuration refers to whether PV arrays are fixed or track the sun on one or two axes. The choice of tracking configuration directly affects area-related BOS costs, O&M costs, and effective insolation. Industry will ultimately select tracking options that result in the lowest system energy cost.

Figure 10 depicts the effects of tracking choice on allowable module costs and efficiencies consistent with the $0.15/kWh energy cost goal. For the baseline values used in this report, one-axis tracking dominates the other two alternatives.

Tables 10, 11, and 12 present PV system energy costs for fixed array, one-axis, and two-axis tracking configurations, respectively. Comparisons of Table 10 with Table 11 show that one-axis tracking dominates for all combinations of module efficiency and module cost when compared to a fixed array system. Comparisons of the one-axis and two-axis tracking systems is not as clear cut. For module costs of \$200/m^2 or less, one-axis tracking dominates. For module costs above \$300/m^2, two-axis tracking dominates. Since commercially available modules are around \$550/m^2, two-axis tracking is presently the optimal tracking configuration.

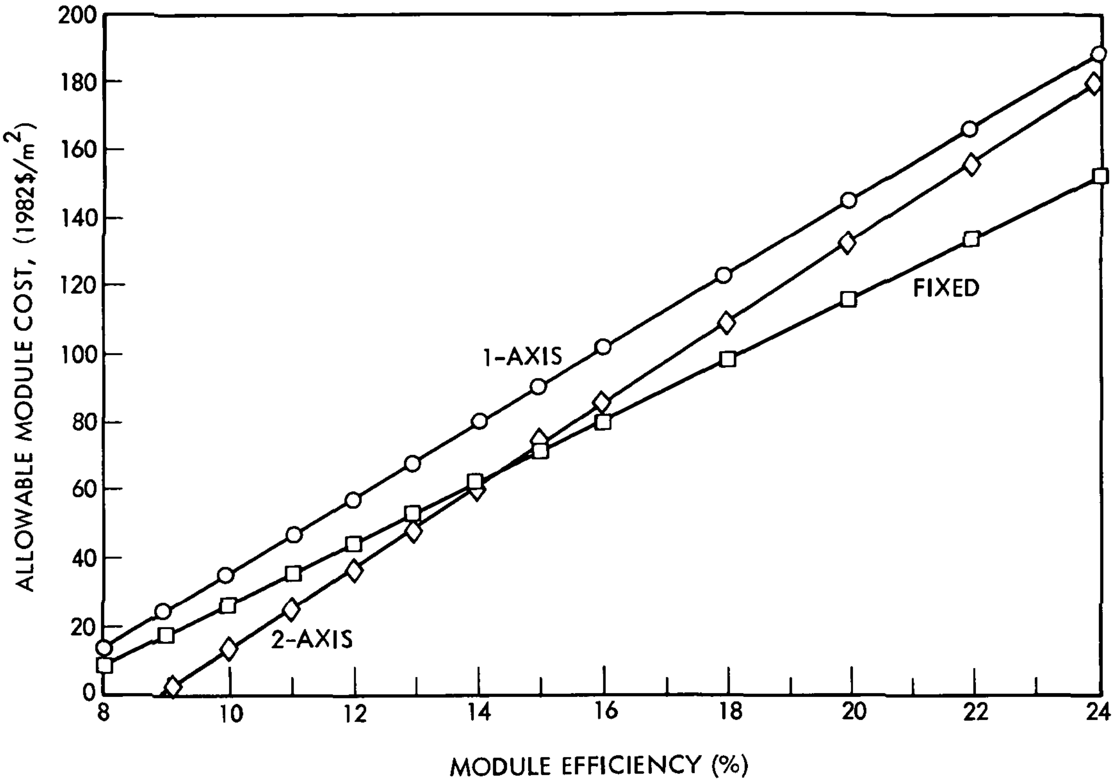


Figure 10. Allowable Module Cost and Efficiency Trade-offs for Alternative Tracking Configurations (1982 Dollars)

Table 10. Levelized Energy Costs for a Fixed Array Configuration (Dollars/kWh)

Module Efficiency	Module Cost						
	30	60	90	120	200	300	550
	Energy Cost						
0.03	0.48	0.63	0.78	0.93	1.33		
0.06	0.25	0.32	0.40	0.47	0.67		
0.08	0.19	0.25	0.30	0.36	0.51		
0.09	0.17	0.22	0.27	0.32	0.45	0.62	
0.10	0.15	0.20	0.25	0.29	0.41	0.56	
0.11	0.14	0.18	0.22	0.27	0.38	0.51	0.85
0.12	0.13	0.17	0.21	0.24	0.35	0.47	0.78
0.13		0.16	0.19	0.23	0.32	0.44	0.73
0.14		0.15	0.18	0.21	0.30	0.41	0.68
0.15		0.14	0.17	0.20	0.28	0.38	0.63
0.16			0.16	0.19	0.26	0.36	0.59
0.18			0.14	0.17	0.24	0.32	0.53
0.20			0.13	0.15	0.21	0.29	0.48
0.22			0.12	0.14	0.20	0.26	0.44
0.24			0.11	0.13	0.18	0.24	0.40

Table 11. Levelized Energy Costs for a One-Axis Tracking Configuration (Dollars/kWh)

Module Efficiency	Module Cost						
	30	60	90	120	200	300	550
	Energy Cost						
0.03	0.44	0.57	0.69	0.82	1.15		
0.06	0.23	0.29	0.35	0.42	0.58		
0.08	0.17	0.22	0.27	0.32	0.44		
0.09	0.16	0.20	0.24	0.28	0.39	0.53	
0.10	0.14	0.18	0.22	0.26	0.36	0.48	
0.11	0.13	0.17	0.20	0.23	0.33	0.44	0.72
0.12	0.12	0.15	0.18	0.22	0.30	0.40	0.67
0.13		0.14	0.17	0.20	0.28	0.37	0.62
0.14		0.13	0.16	0.19	0.26	0.35	0.57
0.15		0.13	0.15	0.18	0.24	0.33	0.54
0.16			0.14	0.17	0.23	0.31	0.50
0.18			0.13	0.15	0.20	0.27	0.45
0.20			0.12	0.14	0.19	0.25	0.41
0.22			0.11	0.12	0.17	0.23	0.37
0.24			0.10	0.11	0.16	0.21	0.34

Table 12. Levelized Energy Costs for a Two-Axis Tracking Configuration (Dollars/kWh)

Module Efficiency	Module Cost						
	30	60	90	120	200	300	550
	Energy Cost						
0.03	0.53	0.65	0.76	0.88	1.19		
0.06	0.27	0.33	0.39	0.45	0.60		
0.08	0.21	0.25	0.29	0.34	0.45		
0.09	0.19	0.22	0.26	0.30	0.41	0.53	
0.10	0.17	0.20	0.24	0.27	0.37	0.48	
0.11	0.15	0.19	0.22	0.25	0.33	0.44	0.70
0.12	0.14	0.17	0.20	0.23	0.31	0.40	0.65
0.13		0.16	0.19	0.21	0.28	0.37	0.60
0.14		0.15	0.17	0.20	0.27	0.35	0.56
0.15		0.14	0.16	0.19	0.25	0.33	0.52
0.16			0.15	0.18	0.23	0.31	0.49
0.18			0.14	0.16	0.21	0.27	0.43
0.20			0.13	0.14	0.19	0.25	0.39
0.22			0.12	0.13	0.17	0.23	0.36
0.24			0.11	0.12	0.16	0.21	0.33

SECTION 4

OTHER SENSITIVITIES

4.1 SUBJECT AREA

The sensitivity of planning goals to factors other than module efficiency and module cost is the subject of this section. These factors fall into three areas: BOS cost and efficiency, indirect costs, and O&M costs. The sensitivity of system energy costs to changes in these parameters was discussed in Section 3.2. In this section, consideration will be given to what are appropriate goals for each of these parameters. Advantage will be taken of the results of some recent studies concerning several of the parameters. Analyses will also be made of how changes in these parameters influence the trade-off between allowable module cost and module efficiency.

4.2 BOS EFFICIENCY

BOS efficiency (i.e., the efficiency of all system components other than modules) is as important as module efficiency in determining system energy costs. A 1% improvement in BOS efficiency is just as effective as a 1% improvement in module efficiency in lowering system energy cost. However, the range of plausible values for BOS efficiency is smaller, reducing the relative significance of this system parameter. Figure 11 shows how gains in BOS efficiency increase allowable module costs. For example, an increase in BOS efficiency from what can be achieved with today's technology (0.836) to the goal value selected for this study (0.865) raises allowable module costs from $\$84/m^2$ to $\$90/m^2$ for 15% efficient modules. These BOS efficiency values are appropriate when calculating levelized busbar energy cost under the conditions assumed in this study. They should not be interpreted as the actual range of BOS efficiencies. See Appendix B for a derivation of the degradation component of BOS efficiency used in this study.

BOS efficiency is the product of seven factors: average dirt accumulation, module degradation, module mismatch, inter-array shadowing, power conditioning system (PCS) efficiency, direct current (DC) wiring losses, and alternating current (AC) wiring losses. Switchyard losses are not included in order to maintain consistency with efficiency estimates made for conventional generating facilities (see Reference 9).

Parasitic losses for the power required to operate tracking drives and computers are not included. ARCO reported parasitic losses of 0.4% for the 6.5 MW Carrisa facility (Reference 16). The major source of power loss was the computer system because the computer system was sized for a much larger PV plant. Losses adjusted for a more reasonable control system design would be negligible. Losses for the power required to operate tracking drives are also negligible. Each drive motor at ARCO's Carrisa plant consumes 0.4 kWh/day (References 17 and 18). Total drive motor losses amount to approximately 0.1% of annual plant energy output (i.e., a 0.999 efficiency factor).

Four BOS efficiency scenarios are described below. These range from a worst case of 75.7% to a maximum of 93.0%. Table 13 summarizes the values of all the loss factors for each scenario. The "maximum" and "minimum"

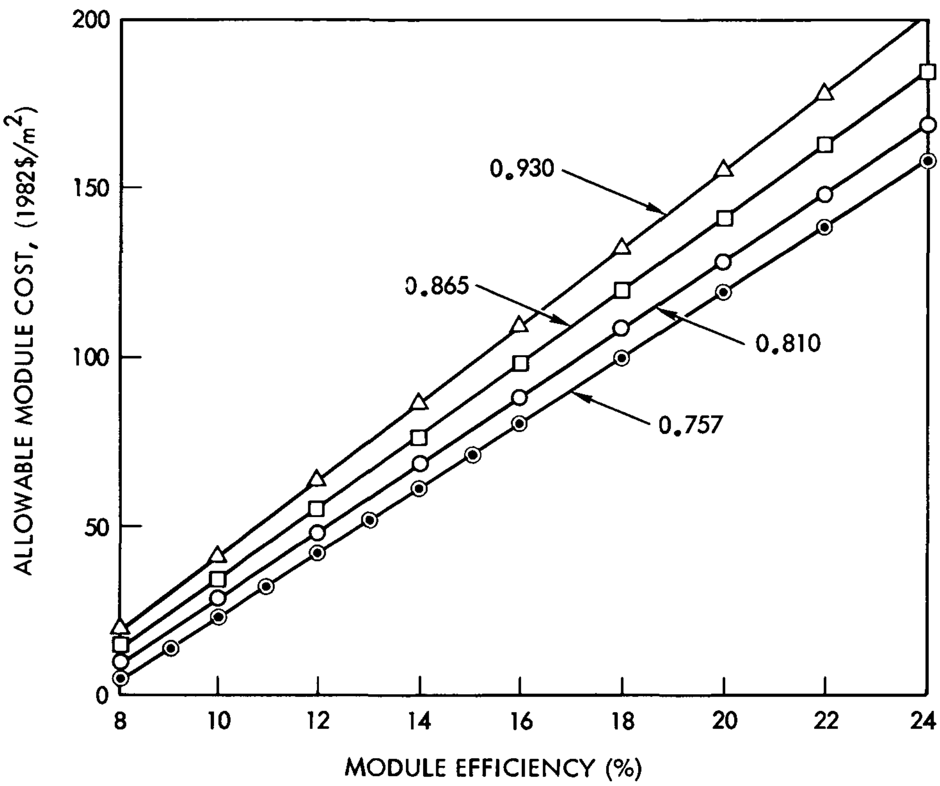


Figure 11. Allowable Module Cost and Efficiency Trade-off for Different BOS Efficiencies (1982 Dollars)

Table 13. BOS Efficiency Cases

Mechanism	Maximum	Baseline	Low	Minimum
Dirt	0.99	0.97	0.95	0.94
Degradation	0.970	0.963	0.95	0.944
Mismatch	0.995	0.99	0.97	0.97
PCS efficiency	0.98	0.95	0.95	0.93
Shadow	0.998	0.99	0.985	0.97
DC efficiency	0.995	0.994	0.994	0.98
AC efficiency	--*	--*	0.995	0.995
Total Product	0.930	0.865	0.810	0.757

*In these scenarios, AC efficiency is included in PCS efficiency.

values correspond to extreme values found in the references used in this analysis, and the "baseline" and "low" cases represent different proposals that have been offered as program goals. The values used in the "baseline" and "low" cases are described in detail below. Although other system parameters are not significantly different for the "baseline" and "low" cases, the "maximum" and "minimum" cases would correspond to different system costs. For instance, the "maximum" case would require frequent washing of panels in order to achieve low dirt losses resulting in higher O&M costs. The costs associated with both the "baseline" and "low" cases are consistent with the baseline values of all other parameters.

The efficiency values presented are based on glass superstrate encapsulants and crystalline silicon cells. Other types of encapsulants may have very different performance characteristics. For instance, studies have shown that dirt losses can be as high as 50% for silicone encapsulants (References 19 and 20).

The accumulation of dirt on panel surfaces reduces the amount of sunlight received by cells. EPRI estimated a factor of 0.95 for dirt losses (see Reference 8). This figure may be appropriate for systems located in an urban location where there are high levels of airborne hydrocarbon pollution and dust. However, central station PV systems will most likely be located in more remote locations with less exposure to the levels of pollution associated with an urban environment. Work performed by JPL shows a first-year average transmission loss of 2.3% for a remote location in California (see Reference 19). For over 2-1/2 years, the average transmission loss has been well under 3% (see Reference 20). A dirt loss efficiency factor of 0.97 is reasonable for a plant in a remote location.

Modules undergo permanent degradation such as the yellowing of encapsulants, aging of cells, and random failures of cell interconnects. EPRI assumed a life-cycle efficiency factor of 0.95 for power losses due to degradation (see Reference 8). This value corresponds to annual degradation losses of 0.65%. R. Ross has suggested a higher efficiency allocation based on a detailed analysis of module degradation mechanisms (References 21 and 22. See Reference 20). Ross considered silicon crystalline cells in long-life encapsulants such as glass, polyvinyl butyral (PVB), and ethylene vinyl acetate (EVA). A conservative estimate of degradation losses consistent with his work is 0.5% per year, resulting in a life-cycle degradation factor of 0.963. (The appropriate method for calculating this factor is discussed in Appendix B.) The "maximum" and "minimum" cases correspond to annual degradation losses of 0.4 and 0.75%, respectively. Degradation losses for modules with cells other than crystal silicon could have much higher degradation losses.

Because individual modules do not have exactly the same maximum power voltage/current point, connecting the thousands of modules of a system in a subfield will result in a fraction of these modules not operating at maximum power. EPRI has assumed a mismatch efficiency of 0.97 to account for this phenomenon (see Reference 8). ARCO reports 3% losses for both dirt and mismatch at Carrisa (Reference 23. See Reference 16). By testing and sorting modules before installation, this efficiency can probably be increased to 0.99 with minimal increase in module cost.

Average PCS efficiency has been estimated by EPRI to be 0.95. This does not include AC subsystem efficiency which was assumed to be 0.995 (Reference 25. See Reference 8). Systems have been installed, such as the one at SMUD, which have attained annual average operating efficiencies of 0.975, including AC subsystem efficiency (Reference 26). However, these high-efficiency line-commutated systems may produce power with levels of harmonic distortion that are unacceptable for significant levels of PV utility grid penetration. Other PCS designs that offer more stable output, such as self-commutated systems, may be slightly less efficient. The ARCO Carrisa plant operates with a 0.939 PCS efficiency, including wiring losses (see References 16 and 23). Work by Westinghouse and others suggests that a 0.95 PCS efficiency, including AC wiring losses, is the best that can be expected of systems that produce large amounts of power suitable for utility interconnection (see Footnote 1). Based on these field reports and engineering studies, an appropriate baseline PCS efficiency is 0.95, including AC subsystem efficiency.

Adjacent arrays may shade each other during certain times of the day and consequently reduce effective insolation and array output. The magnitude of this effect depends on site conditions such as latitude, the amount of direct and diffuse insolation, the time of day when cloud cover is likely, tracking configuration, and the ratio of array spacing to array height (the array spacing factor). EPRI assumed an efficiency factor of 0.985 for shadow losses (see References 8 and 25). However, this efficiency corresponds to suboptimal fixed array spacing factors for locations in the southern United States (Reference 27). Optimal spacing factors that result in the lowest spacing-related energy cost range from 2.5 to 3.0 for the locations studied. At Albuquerque and Miami, this range of spacing factors results in fixed array shadowing efficiencies of 0.990 to 0.997, so that a value of 0.99 can be expected for fixed array systems. Spacing arrays farther apart would increase the shading efficiency, but would decrease wiring efficiencies and increase land and wiring costs.

Shadowing losses for tracking systems may be somewhat higher. ARCO reports annual average losses of 2.5% for their Carrisa installation, which uses two-axis tracking with mirror augmentation (see References 16 and 27). Engineers involved with the Carrisa project feel that future tracking array designs and reduced ground-cover ratios could reduce shadow losses in tracking systems[8]. It is reasonable to expect that tracking systems could achieve shading losses similar to the losses experienced with a fixed array system without increasing system energy costs. This assumes that the plant is constructed in an area with low land costs. Land at the Carrisa site was assessed at $700/acre (see Reference 16). Plants will generally be located in remote sites with low land costs such as this, and perhaps much lower. The California Energy Commission estimates that remote land without water rights sells for as little as $50 to $100 per acre.[9] Therefore, a

[8]Shushnar, G., ARCO Solar Inc., Chatsworth, California, personal communication with M.R. Crosetti, 1984.

[9]Soinksi, A., California Energy Commission, Sacramento, California, personal communication with M.R. Crosetti, 1984.

shadow efficiency of 0.99 has been adopted as the baseline for all tracking configurations.

Losses also occur in the DC subsystem. The magnitude of these losses depends on the gauge and length of DC wiring and on the system voltage. EPRI suggests an efficiency of 0.994 based on numerous runs of a simulation model (see Reference 25). This same analysis shows that DC subsystem efficiency could be as high as 0.999 or lower than 0.95 depending on system design and materials. Attempts to minimize shadow losses can cause a slight increase in DC wiring losses since array spacing would be increased. For shadow efficiencies used in this report, however, there is only negligible increases in DC subsystem losses.

The combined effect of all of these loss mechanisms results in a baseline BOS efficiency of 0.865. ARCO Solar reports an annual BOS efficiency of 0.88, not including module degradation losses, for their 6.5 MW Carrisa PV power plant (see References 16 and 23). If the degradation losses of 0.65% per year are included, then BOS efficiency becomes 0.836. Given the expected advances in PCS technology and system design, a BOS efficiency target of 0.865 is reasonable and appropriate for a national program goal. Recent research supports this figure.

The impact of these different BOS efficiencies on allowable module costs is presented in Table 14 and illustrated previously in Figure 11. Clearly, BOS efficiency has an important effect on allowable module costs and efficiencies.

Table 14. Allowable Module Costs and Efficiency Trade-offs for Different BOS Efficiencies (1982 Dollars)

	BOS Efficiency			
	0.930	0.865	0.810	0.757
Module Efficiency	Allowable Module Cost			
0.08	21	14	9	3
0.09	32	25	19	13
0.10	44	36	29	22
0.11	56	47	39	32
0.12	67	57	49	41
0.13	79	68	59	51
0.14	90	79	65	60
0.15	102	90	80	70
0.16	114	101	90	79
0.18	137	122	110	98
0.20	160	144	130	117
0.22	183	165	150	136
0.24	208	187	171	155

4.2.1 Module Degradation Rate

Modules undergo permanent degradation over time. This degradation includes the yellowing of encapsulants, the aging of cells, random failures of cell interconnects, cell short circuits, and open circuits resulting from cracked cells.

Different degradation rates for current crystalline silicon technology have noticeable effects on allowable module costs. There is a fairly wide range of degradation rates associated with encapsulant materials and crystalline silicon cells. This range results from differences in module design and materials.

On a percentage basis, variations in the degradation rate affect system energy cost as much as variations in module efficiency. As described in the previous section, the baseline degradation rate is 0.5%/yr; extreme crystal silicon module designs could result in degradation rates as high as 2%/yr (see Reference 22). Module technologies other than crystalline silicon may have much higher annual degradation losses, thereby significantly increasing system energy cost. An annual degradation loss of 3% per yr (i.e., a degradation efficiency factor of 0.798), which is within a plausible range for new cell technologies, would increase system energy cost by approximately 20% to $0.18/kWh for baseline assumptions. The effects of different annual degradation losses on allowable module costs and efficiencies are shown in Figure 12. Degradation is potentially a major factor in determining the viability of other new encapsulation methods and advanced cell technologies.

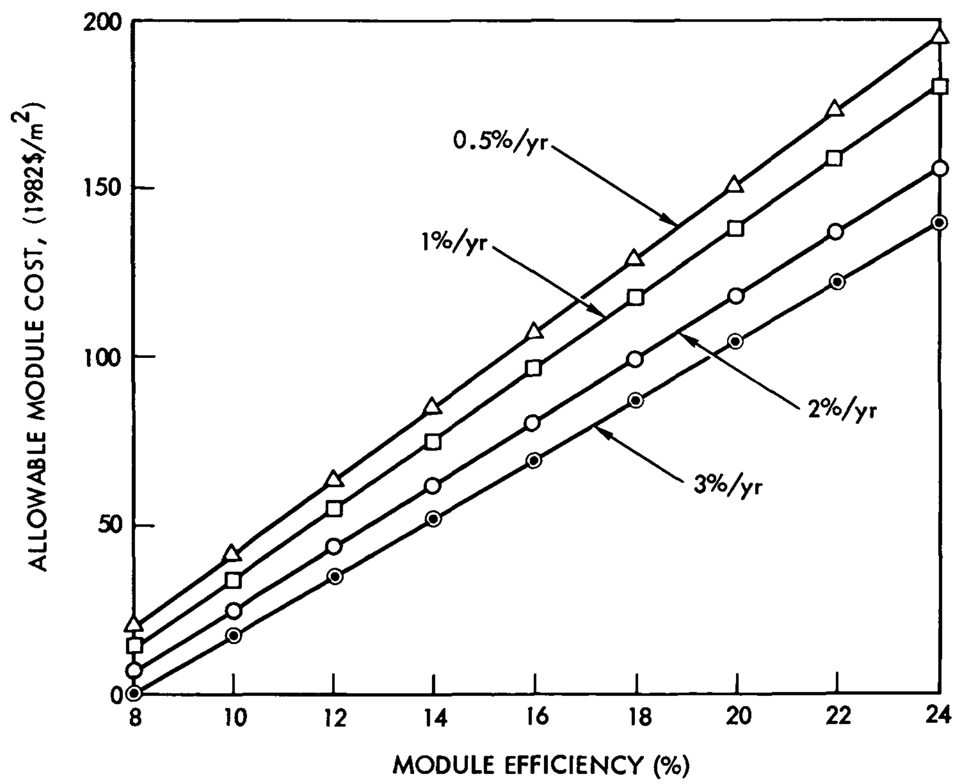


Figure 12. Effect of Module Degradation on Allowable Module Cost and Efficiency Trade-offs (1982 Dollars)

4.3 AREA-RELATED BOS COSTS

Area-related BOS costs include the cost of land, site preparation, array structures, tracking devices, module installation, foundations and other civil construction, instrumentation, surge protection, and grounding. The area-related BOS costs are expressed as dollars per square meter of module area, and these costs vary with the tracking configuration used. Use of higher efficiency modules results in lower system energy costs, in part, because total area-related BOS costs (in terms of dollars per plant) are less for a plant with a given power rating and tracking configuration.

Because there is a fairly broad range of possible area-related BOS costs, this parameter has a significant effect on allowable module cost and efficiency as shown in Figure 13 for a one-axis system.

Area-related BOS cost goals of $\$50/m^2$ for fixed array, $\$58/m^2$ for one-axis tracking, and $\$90/m^2$ for two-axis tracking were selected for this study. These values are supported by a recent study performed by Black and Veatch (see Reference 10). Based on an assessment of anticipated costs for the SMUD PV Phase 3 Project, current area-related BOS costs are

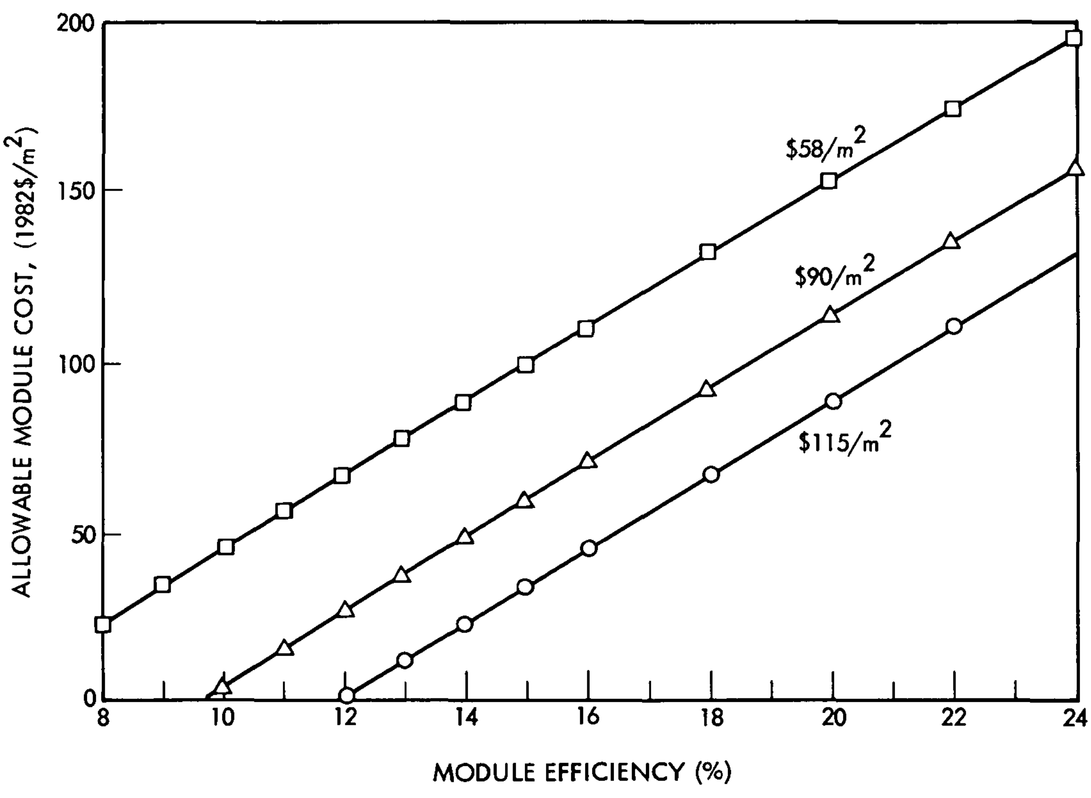


Figure 13. Allowable Module Cost and Efficiency Trade-offs for Different Area-Related BOS Costs (1982 Dollars)

around \$115/m^2 for one axis tracking. An evaluation prepared by ARCO of near-future one-axis area-related BOS costs was \$90/m^2 (see Reference 23). Each of these cases is shown in Figure 13.

4.4 POWER-RELATED BOS COSTS

Power-related BOS costs include the costs of the DC and AC subsystems and the power conditioning system. These costs are expressed as dollars per AC kilowatt of plant capacity. Because of the wide range of potential improvements in this area, power-related BOS costs have a noticeable effect on allowable module cost and efficiency as illustrated in Figure 14.

Current technology yields costs above \$500/kW; power-related BOS costs for Phase 3 of the SMUD PV Project were assessed at \$600/kW (see Reference 3). If a 10% learning curve is assumed for inverter costs (i.e., a 10% cost reduction for each doubling of quantity produced) along with 100 MW of production, power-related BOS costs become \$335/kW. Black and Veatch has estimated mid-1990s power-related BOS costs of \$162/kW to \$199/kW, depending on tracking configuration and location (see Reference 10). The current program goal is \$150/kW.

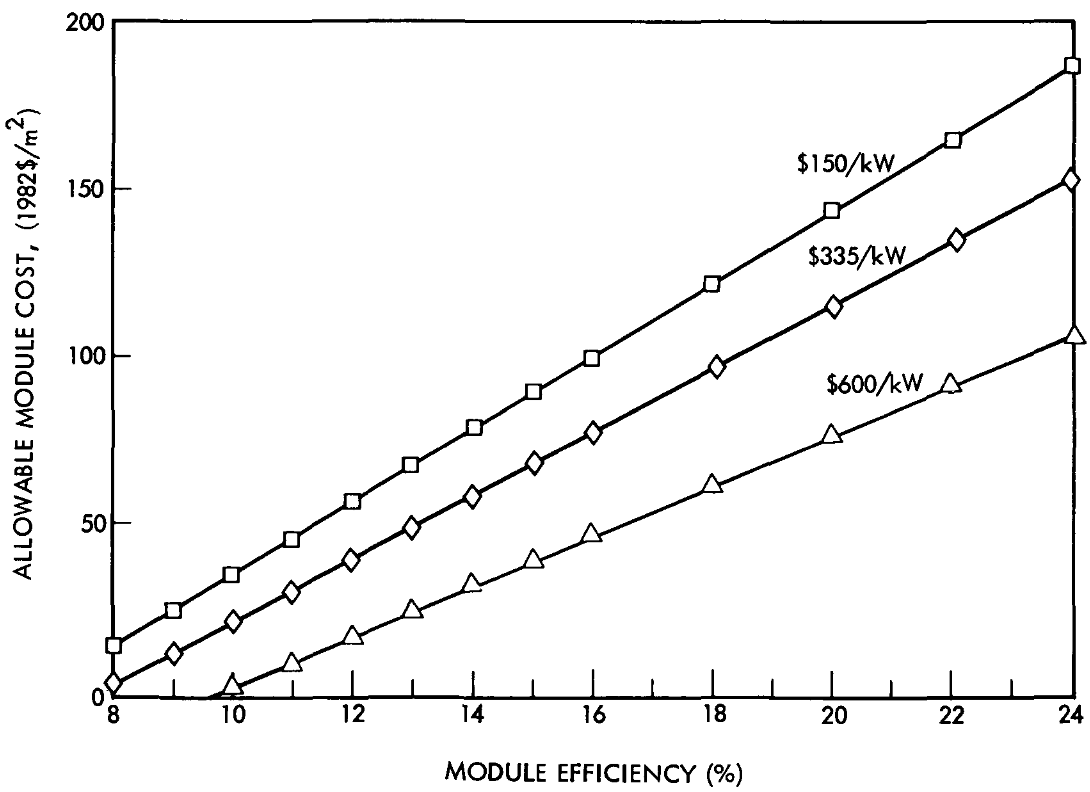


Figure 14. Allowable Module Cost and Efficiency Trade-offs for Different Power-Related BOS Costs (1982 Dollars)

Table 15 presents the allowable module costs corresponding to these power-related BOS cost cases. Although power-related BOS costs have a noticeable effect on allowable module costs, these costs are not as sensitive to power-related BOS costs as to area-related BOS costs. Nonetheless, there are obvious benefits in pursuing an aggressive cost reduction plan for power-related BOS components.

4.5 INDIRECT COSTS

Indirect costs are expenses other than labor and material costs associated with plant construction. These include the costs of engineering services, contingency, interest during construction [sometimes known as the allowance for funds used during construction (AFDC)], other owner's costs, marketing, and distribution. Total indirect costs are expressed as a markup on capital costs.

Table 15. Allowable Module Costs and Efficiency Trade-offs for Different Power-Related BOS Costs (1982 Dollars)

	Power-Related BOS Costs ($/Kw)			
	150	200	335	600
Module Efficiency	Allowable Module Cost			
0.08	14	11	3	-13
0.09	25	22	12	- 6
0.10	36	32	22	2
0.11	47	42	31	9
0.12	57	53	41	16
0.13	68	63	50	24
0.14	79	74	59	31
0.15	90	84	69	38
0.16	101	95	78	46
0.18	122	115	97	61
0.20	144	136	116	75
0.22	165	157	134	90
0.24	187	178	153	105

Values for the indirect cost multiplier have been subject to a great deal of conjecture, primarily because of a lack of actual cost data from which one could empirically derive multipliers. Rules of thumb have often been borrowed from other industries in order to assess the indirect costs of PV systems. However, PV systems are quite different from the systems that these rules of thumb are meant to represent. For instance, because of the relatively simple, modular nature of PV systems, construction times are shorter, interest costs are reduced, and the allocation for contingencies may be less than for conventional power technologies. The indirect multiplier should convey some of the benefits that are unique to PV systems.

Because there is little actual experience with the design and construction of central station PV plants, there is a lack of empirical data to support a particular indirect multiplier. Six sensitivity cases are presented based on a range of indirect multipliers found in various studies. The values for each case are shown in Table 16.

The "minimum" case is based on a system designed by Martin-Marrietta (Reference 28). (Owner's cost, AFDC, and marketing and distribution have been modified for consistency.) The first baseline case was based on the recent study by Crosetti (see Footnote 4). (The component values in this case do not multiply to 1.51 because the indirect multiplier is calculated in a slightly different manner.) The second baseline value is a breakdown of indirect costs proposed by R. Aster[10]. This is the same as an earlier value suggested by R. Taylor at EPRI which did not include marketing and distribution costs. The recommendation by EPRI forms the basis of the "medium," "high," and "maximum" cases. These cases differ only with respect to the marketing and distribution markups. The "high" and "maximum" are suggestions for marketing and distribution markups made elsewhere.[11] All of these cases are meant to correspond to a commercial level of development commensurate with the DOE PV Program goals.

Table 16. Indirect Cost Cases

<table>
<tr><th></th><th>Minimum</th><th colspan="2">Baseline</th><th>EPRI</th><th>Medium</th><th>High</th><th>Maximum</th></tr>
<tr><td>Engineering</td><td>5.6</td><td>14.0</td><td>6.0</td><td>6.0</td><td rowspan="4">51.0</td><td rowspan="4">51.0</td><td rowspan="4">51.0</td></tr>
<tr><td>Contingency</td><td>6.8</td><td>10.0</td><td>15.0</td><td>20.0</td></tr>
<tr><td>Owner's Cost</td><td>7.5</td><td>8.5</td><td>6.0</td><td>6.0</td></tr>
<tr><td>AFDC</td><td>3.0</td><td>3.0</td><td>6.0</td><td>12.0</td></tr>
<tr><td>Marketing</td><td>0.9</td><td>1.1</td><td rowspan="2">10.0</td><td>--</td><td>2.0</td><td rowspan="2">25.0</td><td rowspan="2">40.0</td></tr>
<tr><td>Distribution</td><td>5.0</td><td>7.3</td><td>--</td><td>6.0</td></tr>
<tr><td>Product</td><td>1.32</td><td>1.51</td><td>1.51</td><td>1.51</td><td>1.66</td><td>1.89</td><td>2.11</td></tr>
</table>

[10]Aster, R., Jet Propulsion Laboratory, "The SERI Memo to Annan ve: JPL Concerns about PV Goals," JPL Memo 311.1-1033, December 22, 1983.

[11]McConnell, R., Solar Energy Research Institute, personal communication with Borden, C., 1984.

Each case corresponds to different assumptions about the nature of central station PV plants. The AFDC in the last four cases implies a 2 year construction period for PV plants, and the first two cases correspond to 6 month construction periods. Experience from SMUD, Carrisa, and other system installations demonstrates that the modular and repetitive nature of PV systems decreases the period between the initiation of construction and system startup as compared to conventional systems. ARCO reports that construction of the 4.5 MW Carrisa facility was completed in 7 months by adopting a "factory in the field" approach to plant construction (Reference 24). The "minimum" and first baseline case assumes minimum 6 month construction periods.

The contingency markups represent different estimates of the complexity and the industry's familiarity with the systems. The four highest contingency estimates are derived from the EPRI Technical Assessment Guide (see Reference 9) and are based on experience with the development of conventional generating plants. The lower contingency estimates recognize that PV plants are significantly simpler than other types of generating plants so that fewer problems should be anticipated during installation. The first baseline estimate is based on contingency markups used in planning large windfarm projects that have relatively simple and modular technology like PV, but are more technically mature. This estimate is consistent with the EPRI Technical Assessment Guide contingency recommendations for mature technologies with detailed design plans and cost estimates (see Reference 9). Once PV plant designs are fully developed, similar contingency allocations appear appropriate.

A wide range of central station marketing and distribution (M&D) costs for plant materials has been suggested. The EPRI case omits M&D costs, while the "minimum" and "baseline" cases are derived from SMUD PV project cost data and reasonable marketing scenarios (see Footnote 3). The "baseline" M&D markup results in M&D costs of nearly $10 million for a 100 MW system at goal costs. In contrast, higher M&D markups suggested elsewhere (see Footnote 9) provide the "high" and "maximum" cases, and correspond to costs of $36 to $56 million, respectively, for a 100 MW system.

There is more agreement on engineering and owner's costs. The first baseline engineering markup includes items other than design engineering, such as home office and construction management fees. Owner's costs include the costs of spares, insurance, start-up, licensing, and sales taxes. Baseline values for these components are taken from national construction cost data and SMUD PV costs (see Footnote 4).

The effect of each of these multipliers on allowable module costs is presented in Table 17 and Figure 15. Allowable module costs are as sensitive to indirect costs as to any other parameter. Therefore, in order to establish meaningful goals for module research, it is necessary to have a sound assessment of indirect costs. It is surprising that indirect costs have not been subject to more analytical scrutiny other than the single study mentioned above.

4.6 FIXED CHARGE RATE

The fixed charge rate (FCR) is the percentage of total plant capital construction costs that must be received annually by the utility over the life of the plant to cover the utility's capital investment in the plant. The FCR

Table 17. Allowable Module Costs and Efficiency Trade-offs for Different Indirect Cost Multipliers (1982 Dollars)

	Indirect Cost Multiplier				
	1.32	1.50	1.63	1.89	2.11
Module Efficiency	Allowable Module Cost				
0.08	25	14	8	- 3	- 9
0.09	38	25	18	6	- 2
0.10	50	36	27	14	5
0.11	63	47	37	22	13
0.12	75	57	47	31	20
0.13	87	68	57	39	27
0.14	100	79	67	47	35
0.15	112	90	77	56	42
0.16	125	101	87	64	49
0.18	150	122	106	81	64
0.20	174	144	126	97	79
0.22	199	165	146	114	94
0.24	224	187	165	131	108

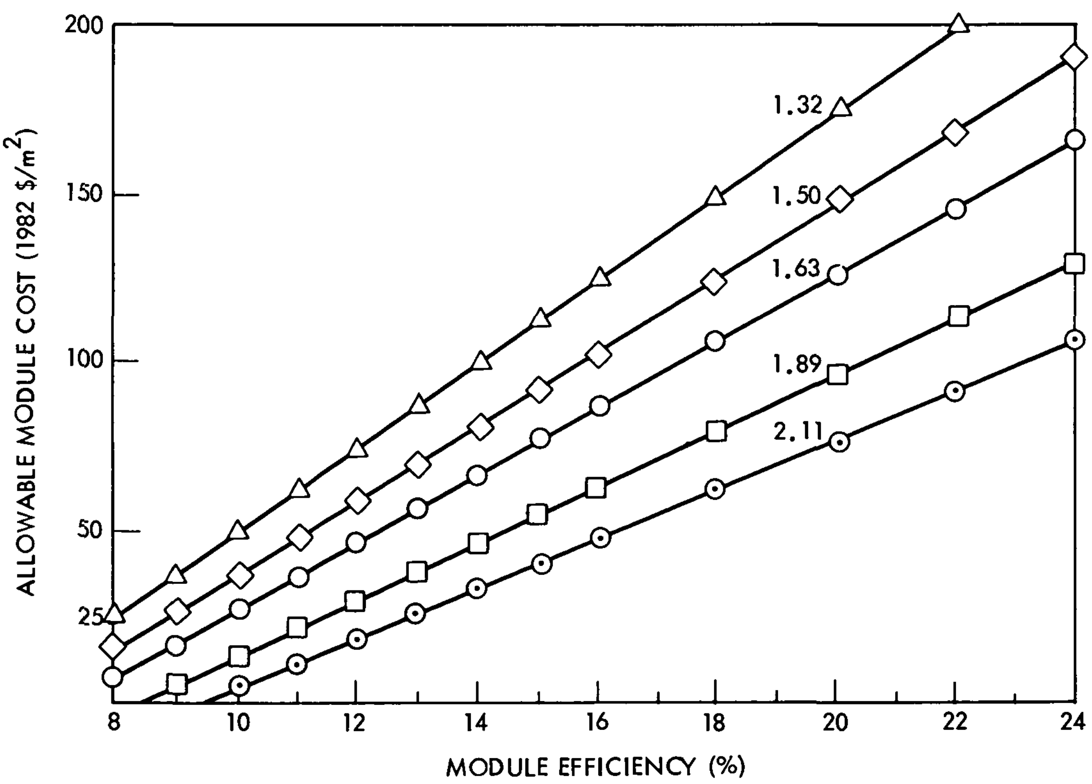


Figure 15. Allowable Module Cost and Efficiency Trade-offs for Different Indirect Cost Multipliers (1982 Dollars)

depends on interest rates, the cost of debt and equity capital, book life, income and property tax considerations, and insurance. Although the actual annual monetary requirements may vary as parameters such as taxes change, the FCR represents a levelized cost factor for recovery of the capital investment.

Because the FCR represents financial considerations that are technology independent, it must be used consistently when comparing two technologies. The 0.153 FCR used for this study is derived from the EPRI Technical Assessment Guide (see Reference 9). This value corresponds to:

(1) An inflation rate of 8.5% and a nominal discount rate of 12.5%. These rates are assumed throughout the Five-Year Research Plan.

(2) A 30 year book life for the plant, consistent with the National Photovoltaics Program lifetime goal.

(3) All tax preferences as granted in the Economic Recovery Tax Act of 1981. EPRI recommends the inclusion of tax preferences in economic analyses.

(4) A 15 year tax recovery period, which is the tax recovery period consistent with the National Photovoltaics Program system lifetime goal.

A change in the FCR used for the evaluation of PV plants must be accompanied by a change in the FCR used for the calculation of the energy cost of competing technologies (i.e. the energy cost goal, EC). Because PV is a capital intensive technology, different FCR's will affect PV technology goals even if they are used consistently in the derivation of an energy cost goal. For instance, Table 18 shows the effects of changing the FCR from 0.153

Table 18. Allowable Module Cost and Efficiency Trade-offs for Different Fixed Charge Rates (1982 Dollars/m^2)

Module Efficiency	Allowable Module Costs for a FCR of 0.153 and a EC of $0.15/kWh	Allowable Module Costs for a FCR of 0.180 and a EC of $0.165/kWh
0.08	14	10
0.09	25	20
0.10	36	30
0.11	47	40
0.12	57	50
0.13	68	60
0.14	79	70
0.15	90	80
0.16	101	90
0.18	122	110
0.20	144	130
0.22	165	150
0.24	187	170

to 0.180. Even though the FCR is changed for both PV and competing systems, resulting in a new energy cost goal of $0.165/kWh, allowable module costs are noticeably reduced. Because the consistent use of a different FCR changes the goals for PV technology, the value used for program planning must be chosen carefully. The value of 0.153 is used because it is consistent with other goals and assumptions used in the Five-Year Research Plan.

4.7 OPERATION AND MAINTENANCE COST

O&M costs are annually recurring expenses for module replacement, salaries of operating personnel, module washing, and the upkeep of the grounds, structure, and electrical systems (including tracking system maintenance). Because there is little data on which to base O&M cost estimates, a wide range of values have been proposed. Cases involving the use of low reliability modules requiring a number of replacements, inappropriate washing and maintenance strategies, and high labor rates result in a significant change in system energy costs. The implications for the trade-off between module efficiency and allowable module cost is depicted in Figure 16. High O&M costs imply significantly more challenging objectives for PV technology development.

There have been several recent attempts to estimate the O&M costs of central station PV plants[12] (see References 10 and 25). Six O&M scenarios were constructed from these estimates with annual O&M costs ranging from $\$0.19/m^2$ to $\$10.02/m^2$ of module area for tracking systems. Table 18 shows the component costs of each scenario.

The major source of variance among these cost estimates is the module replacement rate. This annual rate is given in parenthesis in Table 18 under the associated replacement cost for each scenario. The 50 per 1000 replacement rate is slightly worse than the first 6.75 years of Block I module field experience and may be the result of fielding new types of untested modules (Reference 29). (The criterion for module failure was that the module produced less than 75% of its original power.) The baseline value of 4 per 1000 rate is an allocation derived from engineering studies performed by R. Ross (see Reference 20). The minimum cost scenario contains negligible module replacements, 1 per 100,000. In all cases, replacement costs include $\$0.04/m^2$ for the detection of modules that must be replaced (see Reference 26).

The baseline estimate for O&M costs is based on reported ARCO experience, where the system is completely automated and no module washing occurred (see Reference 29). Two of the scenarios include panel washing. If washing is performed, then compensating changes must be made in BOS efficiency for consistency. Table 19 shows the effects of panel washing on allowable module cost for a one-axis tracking system. These results indicate that for glass encapsulated modules in remote locations, there is no benefit from washing.

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[12]Soinski, Art, California Energy Commission, "Operation and Maintenance Costs for a Conceptual 100 MW Photovoltaic Power Plant," C.E.C. Internal Memo, August 8, 1983.

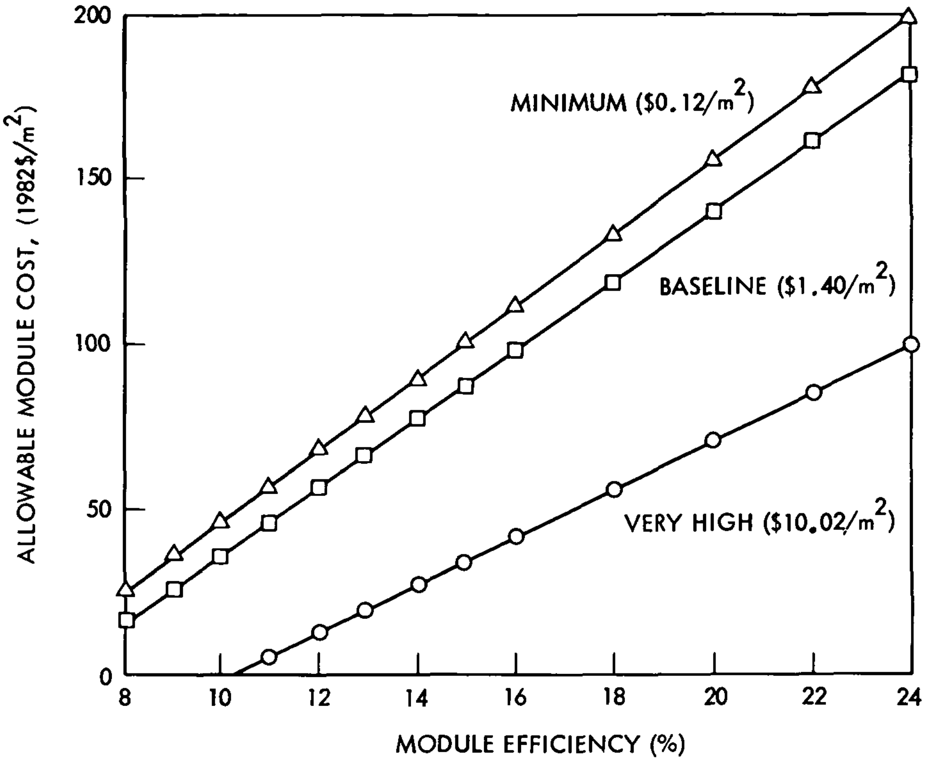

Figure 16. Allowable Module Cost and Efficiency Trade-offs for Different O&M Costs (1982 Dollars)

Grounds, structural, and electrical upkeep include estimates of the cost of weed control, fence maintenance, and other minor maintenance activities. The medium estimate is adequate for 1 to 2 weeks of labor per acre of land each year. There is no evidence of major upkeep problems for fixed flat plate systems. Tracking systems do require additional maintenance, and the additional cost is based on Martin Marrietta experience as estimated by Black and Veatch (see Reference 10).

Baseline O&M costs provide a conservative estimate based on data available to date. Table 20 shows the combinations of module cost and efficiency allowable under the various O&M scenarios for one-axis systems and the \$0.15/kWh energy cost goal.

The current formulation of O&M costs in the <u>Five-Year Research Plan</u> holds the cost of replacement modules fixed at \$90/m^2 and assumes a given replacement rate. It has been pointed out by A. Scolaro of DOE and others that O&M costs are more appropriately modeled as a function of module costs and replacement rates. Figure 16 and Tables 19, 20 and 21 assume that replacement module costs are equal to initial module costs. Table 22 gives system energy cost rather than allowable module cost and efficiency trade-offs.

Table 19. Six O&M Cost Scenarios (1982 Dollars/m^2)[a]

	Very High	High	Baseline	Low	Very Low	Minimum
Operations Including:	0.19	0.15	0.06	0.06	0.0	0.0
1 Manager	Yes	Yes	Yes	Yes	No	No
2 Controllers	Yes	Yes	No	No	No	No
1 Clerk	Yes	No	No	No	No	No
Washing (Washings/Yr)	0.48 (12)	0.24 (6)	0.0 (0)	0.0 (0)	0.0 (0)	0.0 (0)
Grounds, Structure, and Electrical Upkeep ($/Acre)	1.11 (1500)	0.74 (1000)	0.44 (600)	0.30 (400)	0.15 (200)	0.075 (100)
Module Replacement[b] (Replacement Rate)	7.04 (50/1,000)	1.44 (10/1,000)	0.60 (4/1,000)	0.18 (1/1,000)	0.06 (1/10,000)	0.04 (1/100,000)
Fixed Totals	8.82	2.57	1.10	0.54	0.21	0.115
Tracking Maintenance[c]	1.20	0.60	0.30	0.30	0.15	0.075
Tracking Totals	10.02	3.17	1.40	0.84	0.36	0.19

[a]Based on a 100 MW plant size, 1:3 array to land ratio.

[b]Includes 0.04 for inspection and detection, plus $140/$m^2$ for replacement.

[c]Black and Veatch estimated 0.30 based on Martin Marrietta's preliminary data on two-axis tracking failure and repair rates.

Table 20. Effects of Panel Washing on One-Axis Tracking Allowable Module Costs (1982 Dollars/m^2)

Washings/Yr	12	6	0
Soiling Efficiency	98.5%	98%	97%
Replacement Rate	0.004	0.004	0.004
Other O&M Costs	1.32	1.08	0.84
BOS Efficiency	0.878	0.874	0.865
Module Efficiency	Allowable Module Cost		
0.08	14	16	17
0.10	35	37	38
0.12	56	58	59
0.14	77	79	79
0.15	87	89	90
0.16	98	100	100
0.18	119	121	121
0.20	140	142	142
0.22	161	163	162
0.24	182	183	183

Table 21. Module Costs and Efficiency Trade-offs for Different O&M Costs with Replacement Costs Equal to Original Module Costs (1982 Dollars/m^2)

	Maximum	High	Baseline	Low	Very Low	Minimum
Replacement Rate	0.05	0.01	0.004	0.001	0.0001	0.00001
BOS Efficiency	0.878	0.878	0.865	0.865	0.865	0.865
Module Efficiency	Allowable Module Cost					
0.08	-17	6	17	21	25	26
0.10	- 3	26	38	42	46	48
0.12	12	46	59	63	68	70
0.14	26	66	79	85	90	91
0.15	34	76	90	95	100	102
0.16	41	86	100	106	111	113
0.18	55	106	121	127	133	134
0.20	70	126	142	149	154	156
0.22	85	145	162	170	176	178
0.24	99	165	183	192	197	199

Table 22. Levelized System Energy Cost with Replacement Costs Equal to Original Module Costs (1982 Dollars/m^2)

		Maximum	High	Baseline	Low	Very Low	Minimum
Replacement Rate		0.05	0.01	0.004	0.001	0.0001	0.00001
BOS Efficiency		0.878	0.878	0.865	0.865	0.865	0.865
Module Efficiency	Cost	System Energy Cost					
0.12	550	1.16	0.85	0.81	0.78	0.77	0.77
0.15	550	0.93	0.68	0.65	0.63	0.62	0.62
0.18	550	0.78	0.57	0.54	0.53	0.52	0.52
0.20	550	0.70	0.52	0.49	0.48	0.47	0.47
0.12	300	0.69	0.51	0.48	0.47	0.46	0.46
0.15	300	0.56	0.41	0.39	0.38	0.37	0.37
0.18	300	0.47	0.34	0.33	0.32	0.31	0.31
0.03	200	1.97	1.44	1.35	1.31	1.28	1.28
0.12	200	0.51	0.37	0.35	0.34	0.33	0.33
0.15	200	0.41	0.30	0.28	0.28	0.27	0.27
0.18	200	0.34	0.25	0.24	0.23	0.23	0.23
0.10	90	0.36	0.26	0.25	0.24	0.23	0.23
0.12	90	0.30	0.22	0.21	0.20	0.20	0.19
0.15	90	0.24	0.18	0.17	0.16	0.16	0.16
0.18	90	0.21	0.15	0.14	0.14	0.14	0.14
0.03	30	0.70	0.51	0.46	0.44	0.43	0.43
0.08	30	0.28	0.20	0.18	0.18	0.17	0.17
0.10	30	0.22	0.17	0.15	0.15	0.14	0.14
0.12	30	0.19	0.14	0.13	0.12	0.12	0.12

SECTION 5

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APPENDIX A

CURRENT STATUS OF CENTRAL STATION PV

Throughout this study, current state-of-the-art values for many parameters have been reported. By considering current values for parameters, a picture emerges of PV's present status and the effort required to meet program goals.

Three cases are described. The first case leaves all economic and meteorological values unchanged from the program values. Technical values, however, are drawn from projections of SMUD Phase 3 costs and performance (see Reference 3). By comparing the system energy costs of this case with the \$0.15/kWh goal gives an indication of the aggressiveness of the national PV program. The other two cases include current technical values and economic and meteorological values that correspond to Southern California and the Northeast. These cases reflect some of the regional differences faced by the technology.

Area-related BOS costs for SMUD Phase 3 are in the region of \$113/m^2 to \$121/m^2, and power-related BOS costs range from \$567/kW to \$659/kW. For this analysis, area-related BOS costs are assumed to be \$115/m^2, and power-related BOS costs are assumed to be \$600/kW. Modules are assumed to have an efficiency of 11.5% STC and a cost of \$550/m^2 based on ARCO's sales to SMUD. BOS efficiency is set at 0.836, which is the rate reported by ARCO for their Carrisa installation after adjusting for module degradation of 0.65%/yr. O&M costs are set to \$3.24/m^2 for energy cost calculations to cover the higher module replacement costs.

For technical values corresponding to the current state of the art and recommended insolation levels, the resulting energy cost is \$0.85/kWh compared to an energy cost goal of \$0.15/kWh. Using these same values and the \$0.15/kWh energy cost goal, allowable modules costs are -\$41/m^2 (negative) at 11.5% efficiency. As suggested earlier in Figure 1, closing this gap requires improvement in the cost and performance of all system components, and not just modules.

The energy cost for the Northeast case, assuming insolation for Long Island,[A-1] is \$1.05/kWh. This reflects the region's poorer insolation. When a competitive energy cost of \$0.20/kWh is used rather than the \$.15/kWh goal, allowable module costs become -\$25/m^2 at 11.5% efficiency. Higher competing energy costs in the Northeast can offset the effects of lower insolation. If technical program goals are met, PV may even be competitive in the Northeast, as suggested previously in Figure 2.

Southern California is perhaps the most promising area for PV. In fact, the three largest existing central station PV plants are located in

[A-1]Cottingham, J.G., Brookhaven National Laboratory, "Normal Incident Solar Radiation Measurements at Upton, New York," BNL 50939, Upton, N.Y., 1979.

California (SMUD, Carrisa, and Lugo). Southern California is characterized by good insolation and high competitive energy costs. Assuming that PV installations are constructed in regions of Southern California with the best insolation, the energy cost resulting from current technical values is \$0.70/kWh. With a competitive energy cost of \$0.20/kWh, allowable module costs are \$35/m^2 at 11.5% efficiency. Even if other technical parameters were not improved, 15% modules would have to cost \$84/m^2 to make PV viable in this region. This is one region where PV may be viable before all program goals have been met.

There has been a sharp reduction of PV costs since the Block 1 module purchase in 1975. At that time, modules cost over \$2100/m^2 for 6% efficient modules.[A-2] Assuming the current values for other parameters, these module characteristics result in an energy cost of \$4.56/kWh. Today, 11.5% efficient \$550/m^2 modules are commercially available, and the technology exists to reduce module costs to \$200/m^2; these modules could produce energy for \$0.31/kWh, an eleven-fold reduction in cost, and only twice the energy cost goal.

[A-2]Christiansen, E., Jet Propulsion Laboratory, "Electricity from Photovoltaic Solar Cells: Low-Cost Solar Array Projects," Pasadena, California, May 1981 (Presentation from 15th Annual Photovoltaic Specialist Conference).

APPENDIX B

DERIVATION OF THE LIFE-CYCLE MODULE DEGRADATION EFFICIENCY FACTOR

Annual PV system output decreases overtime due to module degradation. In order to incorporate this effect into the derivation of a levelized system energy cost, one must consider how degradation affects the required revenues of the plant.

The calculation of energy cost in the DOE Five Year Research Plan is based on a revenue requirements methodology. This methodology requires that the present value of all revenues generated by the plant over its lifetime must equal its life-cycle cost.

The Five Year Research Plan and this Sensitivity Analysis state the PV energy cost goal in terms of nominally levelized busbar energy cost (BBEC). BBEC is the one single energy price the utility could charge over the entire life of the plant and recover total life-cycle costs. In order to determine the effect of module degradation on BBEC, one can write:

$$\text{REQREV} = \text{LCC}$$

$$\sum_{i=1}^{N} \frac{1}{(1 + K)^{i}} \; \overline{\text{BBEC}} \cdot \text{MWH}_i = \sum_{i=1}^{N} \frac{1}{(1 + K)^{i}} \; \text{AC}_i$$

$$\overline{\text{BBEC}} \cdot \sum_{i=1}^{N} \frac{i}{(1 + K)^{i}} \cdot \text{MWH}_a \, (1 - d)^{i} = \sum_{i=1}^{N} \frac{1}{(1 + K)^{i}} \, \text{AC}_i$$

where:

K = discount rate, nominal (real) if costs are in current (constant) terms.

$\overline{\text{BBEC}}$ = levelized busbar energy cost (or, alternately, required price).

AC_i = annual system costs in year i.

MWH_i = energy production in year i.

N = plant lifetime in years

d = annual percentage energy loss due to degradation of modules.

MWH_a = constant annual energy output excluding degradation.

In the previous equations, both revenues and life-cycle costs were expressed as present values. In order to change these present values into uniform annualized amounts, we can multiply by the capital recovery factor:

$$\mathrm{CRF} \cdot \overline{\mathrm{BBEC}} \cdot \sum_{i=1}^{N} \frac{(1-d)^i}{(1+K)^i} \mathrm{MWH}_a = \mathrm{CRF} \cdot \sum_{i=1}^{N} \frac{1}{(1+K)^i} \mathrm{AC}_i$$

$$\mathrm{CRF} \cdot \overline{\mathrm{BBEC}} \cdot \sum_{i=1}^{N} \frac{(1-d)^i}{(1+K)^i} \mathrm{MWH}_a = \overline{\mathrm{AC}}$$

where $\overline{\mathrm{AC}}$ is levelized annual system costs.

To find the effect of degradation on levelized energy cost, we can solve for $\overline{\mathrm{BBEC}}$:

$$\overline{\mathrm{BBEC}} = \frac{\overline{\mathrm{AC}}}{\mathrm{MWH}_a} \cdot \frac{1}{\left[\mathrm{CRF} \cdot \sum_{i=1}^{N} \frac{(1-d)^i}{(1+K)^i}\right]}$$

The term in brackets is the life-cycle degradation efficiency factor. Since $\overline{\mathrm{BBEC}}$ is given in current dollar terms, K is the nominal discount rate. The use of this result to determine the effects of module degradation on allowable module costs can only be done in the context of a revenue requirements methodology that relies on levelized energy cost as a measure of a system's value.

It may appear in the last few equations that energy production is discounted. Future energy production is not discounted because energy produced in the future is inherently worth less than energy produced now (i.e. there is no time value of energy per se). Rather, energy produced in the future creates future revenues that must be discounted to provide present values and levelized costs. Because of the mathematical nature of the formula that calculates levelized energy costs, discounting and levelizing revenues can be reduced to discounting and levelizing module degradation losses.

APPENDIX C

THE DIFFERENCE BETWEEN NOMINAL AND REAL LEVELIZED ENERGY COSTS

The cost of building and operating a power generator helps determine the price that must be paid for that energy. However, costs are not evenly distributed over time. Typically there are large initial costs for capital investment, followed by lower fuel and operations costs which recur annually and occasional major maintenance costs which may occur every few years. These uneven cost streams must be levelized in order to obtain a single, uniform energy price over time for the utility.

There are two types of levelization, real and nominal. Real levelization is the method that most often allows a direct comparison between the costs of different types of power sources. Nominal levelization closely approximates actual utility accounting practice, and is the method adopted by DOE for calculating system energy cost.

Nominal levelization treats the initial capital investment in a manner that is very much like a fixed rate mortgage on a home. Each year a fixed number of dollars are set aside to meet the costs of the investment. Because a fixed number of dollars are set aside, inflation will reduce the value of those payments over time. With nominal levelization, the number of dollars spent each year is levelized but the value of the payment declines.

With real levelization, the value of each year's payment is levelized, but the exact number of dollars in each payment will increase with inflation. This method produces costs that can be compared to current energy costs. This method also allows comparison between systems that have different lifetimes.

Both methods work on the principle that the present value of all costs are recovered by a uniform stream of revenue. If there was no inflation, both methods would yield identical results. Real levelization results in payments or prices that are constant in value. Nominal levelization, used in the Five-Year Research Plan and this study, results in payments that are constant in dollar amount, but which decline in value from one year to the next because of inflation.

Figure C-1 shows how a real levelized payment of constant dollar value (dashed line), grows in current dollar amounts as the result of an 8.5% inflation rate. If this stream of increasing current dollar payments is levelized using the nominal (inflation-included) discount rate of 12.5%, the magnitude of each year's nominal levelized payment (solid flat line) in current dollars is greater than the magnitude of the real levelized payment in constant dollars because the nominal levelized payment includes the effects of inflation.

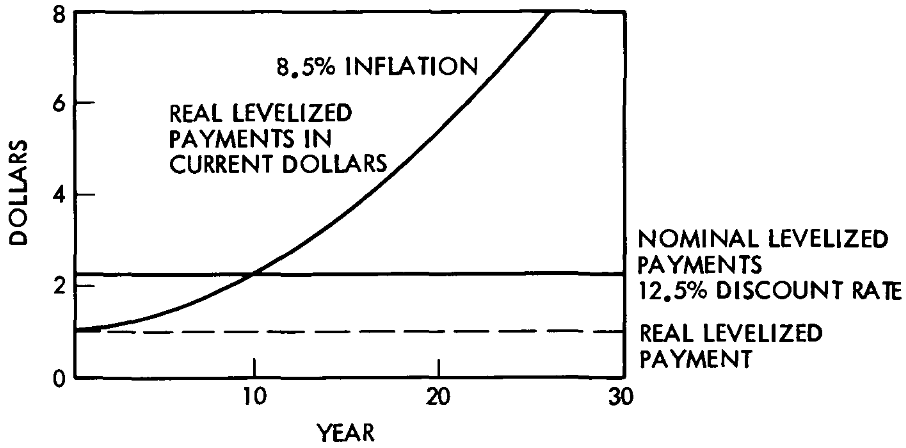

Figure C-1. The Difference Between Nominal and Real Levelized Energy Costs